

Greenhouse Gas PSD Permit Application

C3 Petrochemicals LLC
Propane Dehydrogenation Unit
Chocolate Bayou Plant
Alvin, Texas

Prepared for:
C3 Petrochemicals LLC

Prepared by:
ENVIRON International Corporation
Houston, Texas

Date:
February 2013
Revised July 2013

Project Number:
31-30172C

ENVIRON

Contents

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1 Introduction

Project Overview

C3 Petrochemicals LLC (C3P) is planning to build a new propane dehydrogenation (PDH) manufacturing unit near the city of Alvin, Brazoria County, Texas. When constructed, the new PDH unit will be located on land owned by Ascend Performance Materials Texas, Inc. (Ascend) at its existing Chocolate Bayou (CHB) Chemical Manufacturing Complex. The CHB complex is located on FM 2917, approximately 8 miles south of the intersection of Highway 35 and FM 2917 (Figure 1).

Construction of the PDH plant is scheduled to begin in January 2014 and plant startup will commence in the fourth quarter of 2015.

The C3P PDH unit will use propane as its raw materials, which will be dehydrogenated to produce polymer-grade and chemical grade propylene. This propylene product will be distributed to customers via pipeline.

Sources of Air Emissions

Activities at the proposed C3P PDH unit that will result in the emission of greenhouse gases include:

- Heaters;
- Boilers;
- Process vents;
- Process fugitives;
- Process flare;
- Routine maintenance, startup, and shutdown emissions.

Figure 1. Location of Proposed C3P PDH Unit
(Map Created Using Google Earth)

Emissions of oxides of nitrogen (NO_X) from the proposed PDH unit will exceed the significance threshold of 25 tons per year (tpy) for Nonattainment New Source Review (NNSR) in the Houston/Galveston/Brazoria ozone nonattainment area. Therefore, this project is subject to federal NNSR.

In addition, the PDH unit will be subject to federal Prevention of Significant Deterioration (PSD) review for NO_X, carbon monoxide (CO), particulate matter (PM), PM less than 10 micrometers in diameter (PM_{10}), PM less than 2.5 micrometers in diameter ($PM_{2.5}$), and greenhouse gases (GHGs) quantified as carbon dioxide equivalents (CO_2e). Emissions of sulfur dioxide (SO_2) are below the significance threshold for PSD permitting.

On June 3, 2010, the United States Environmental Protection Agency (EPA) published final rules for permitting sources of GHGs under the PSD and Title V air permitting programs, known as the GHG Tailoring Rule.[1] On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue GHG permits in Texas until Texas submits the required State Implementation Plan (SIP) revision and this revision is approved by EPA.[2] Since the Texas Commission on Environmental Quality (TCEQ) has not submitted the required SIP revisions to EPA and has not implemented a PSD permitting program for GHGs, the purpose of this application is to obtain air quality permit authorization from EPA to authorize GHG emissions from the proposed new PDH plant near Alvin, Texas. C3P believes that this application has been prepared such that it contains all information necessary for processing the application as described in 40 CFR §52.21(b)(22). The proposed PDH plant will not be located within 100 km of a designated Class I federal area and the emissions of GHGs from the plant will not affect air quality at any of these designated Class I areas.

A separate air preconstruction permit application has been submitted to the TCEQ to authorize emissions of all regulated air pollutants except for GHGs. This TCEQ permit application is consistent with the requirements in Title 30 of the Texas Administrative Code (30 TAC) Chapter 116, Subchapter B, Division 1.

Emissions from each of the sources in the PDH plant will be addressed in the GHG Emissions Calculations and Best Available Control Technology (BACT) sections of this application for all GHGs.

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[1] 75 FR 31514 (June 3, 2010)

[2] 75 FR 81874 (December 29, 2010)

2 General Application Information

2.1 TCEQ Form PI-1

TCEQ

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: C3 Petrochemicals LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Dale Borths		
Title: VP - Environmental, Safety, Security and Health		
Mailing Address: 600 Travis, Suite 300		
City: Houston	State: Texas	ZIP Code: 77002-2931
Telephone No.: 256-552-2204	Fax No.: 256-552-2153	E-mail Address: dlbort@ascendmaterials.com
C. Technical Contact Name: Ray Lewis		
Title: Environmental Specialist		
Company Name: C3 Petrochemicals LLC		
Mailing Address: 600 Travis, Suite 300		
City: Houston	State: Texas	ZIP Code: 77002-2931
Telephone No.: 281-228-4400	Fax No.: 281-228-4869	E-mail Address: rclewi1@ascendmaterials.com
D. Site Name: PDH- Chocolate Bayou Plant		
E. Area Name/Type of Facility: PDH Plant		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Chemical Manufacturing		
Principal Standard Industrial Classification Code (SIC): 2869		
Principal North American Industry Classification System (NAICS): 325110		
G. Projected Start of Construction Date: January 2014		
Projected Start of Operation Date: December 2015		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: Located on FM 2917, approximately 8 miles south of the intersection of Texas Hwy 35 and FM 2917		
City/Town: Alvin	County: Brazoria	ZIP Code: 77512-0711
Latitude (nearest second): 29°15'24" N	Longitude (nearest second): 95°12'52" W	

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility):	
J.	Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☐ YES ☒ NO
K.	Customer Reference Number (CN): CN604259192	
L.	Regulated Entity Number (RN): RN106592579	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: 40	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Larry Taylor		District No.: 11
State Representative: Ed Thompson		District No.: 29
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested.	
☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation		
B.	Permit Number (if existing):	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source		
☐ Other:		
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III. Type of Permit Action Requested *(continued)*			
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0			☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.			☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?			☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.			
List: None			
G. Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.			☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).		☒ YES ☐ NO ☐ To be determined	
Associated Permit No (s.):			
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.			
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision	
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP	
☒ To be Determined		☐ None	

TCEQ

III. Type of Permit Action Requested *(continued)*		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*		
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***		
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued	☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability		
A. Is this a new permit application or a change of location application?		☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.		☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?		☐ YES ☒ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?		☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.		
1. Is there any change in character of emissions in this application?		☐ YES ☐ NO
2. Is there a new air contaminant in this application?		☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?		☐ YES ☐ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***		
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NOx):		
Particulate Matter (PM):		
PM 10 microns or less (PM10):		
PM 2.5 microns or less (PM2.5):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants not listed above: CO2e = 795,881		

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Ray Lewis		
Title: Environmental Specialist		
Mailing Address: 600 Travis, Suite 300		
City: Houston	State: Texas	ZIP Code: 77002-2931
B. Name of the Public Place: Alvin Library		
Physical Address *(No P.O. Boxes)*: 105 South Gordon Street		
City: Alvin	County: Brazoria	ZIP Code: 77511
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Joe King		
Mailing Address: 111 E. Locust Street, Suite 102		
City: Angleton	State: Texas	ZIP Code: 77515
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive:		
Mailing Address:		
City:	State:	ZIP Code:
Name of the Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:

V.	**Public Notice Information *(complete if applicable) (continued)***	
C.	Concrete Batch Plants, PSD, and Nonattainment Permits	
3.	Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s):		
D.	Bilingual Notice	
Is a bilingual program required by the Texas Education Code in the School District?		☐ YES ☒ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☒ YES ☐ NO
If Yes, list which languages are required by the bilingual program?		Spanish
VI.	**Small Business Classification *(Required)***	
A.	Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B.	Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C.	Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D.	Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII.	**Technical Information**	
A.	The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1.	☒ Current Area Map	
2.	☒ Plot Plan	
3.	☐ Existing Authorizations	
4.	☒ Process Flow Diagram	
5.	☒ Process Description	
6.	☒ Maximum Emissions Data and Calculations	
7.	☐ Air Permit Application Tables	
a.	☐ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b.	☐ Table 2 (Form 10155) entitled, Material Balance	
c.	☐ Other equipment, process or control device tables	
B.	Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

VII.	Technical Information			
C.	Maximum Operating Schedule:			
Hour(s): 24	Day(s): 7	Week(s): 52	Year(s): 8,760	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
E.	Does this application involve any air contaminants for which a disaster review is required?			☒ YES ☐ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?			☐ YES ☒ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☒ YES ☐ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number:		Fee Amount: $ N/A
Paid online?		☐ YES ☐ NO
Company name on check:		
Is a copy of the check or money order attached to the original submittal of this application?		☐ YES ☐ NO ☒ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☐ YES ☐ NO ☒ N/A

XII. Delinquent Fees and Penalties
This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Dale Borths
Signature: Dale Borths *Original Signature Required*
Date: 7/18/13

PRINT FORM RESET FORM

2.2 Plot Plan

List of Emission Points

EPN	UTMx (meters)	UTMy (meters)
PDH-H201	284900.4	3238370.01
PDH-H202	284881.33	3238387.6
PDH-H203	284866.15	3238402.04
PDH-H204	284856.52	3238410.37
CCR-2	284914.84	3238385.56
PDH-H104	284733.7	3238524.83
PDH-H103	284724.95	3238533.15
PDH-H102	284709.62	3238547.31
PDH-H101	284690.93	3238564.54
CCR-1	284704.8	3238580.45
PDH-CT	284625.95	3238396.24
PDH-BOILERS	284776.45	3238262.65
PDH-FLARE	284649.84	3238880.2

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DRAFTED BY: gmiles

DATE: 1/8/2013

Plot Plan

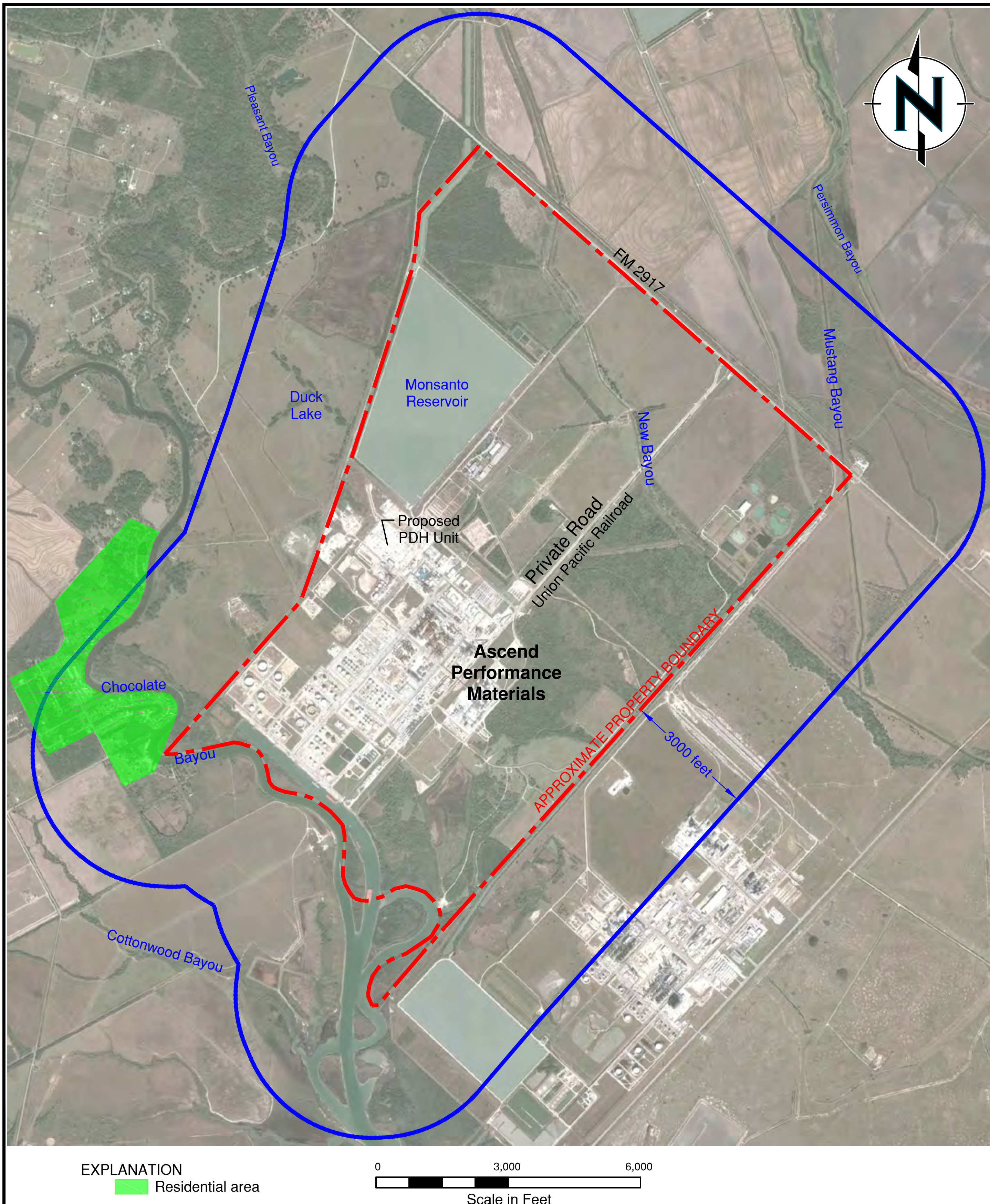
C3 Petrochemicals LLC PDH Unit

Chocolate Bayou Complex

Figure **3**

C:\Projects\31-30172B\EPN Locations2.mxdt

2.3 Area Map



Aerial Photograph Source: © Google 2012; dated November 2011.

C:\PROJECTS\31-30172B\SITE LAYOUT CHOCOLATE BAYOU TX.DWG

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Area Map

C3 Petrochemicals LLC PDH Unit
Chocolate Bayou Complex

Figure **2**

DRAFTED BY: \GMILES

DATE: 1/9/2013

3 Process Description and GHG Emission Sources

3.1 Process Description

Overview

C3P is planning to build a new propane dehydrogenation (PDH) unit near the city of Alvin in Brazoria County, Texas. This plant will use propane as its primary raw material. The sale of propylene and other products of the PDH reaction will vary in response to marketplace and customer demands.

Major sections of the PDH process at the proposed facility include:

- Feed Pre-Treatment;
- Heavies Removal;
- PDH Reaction;
- Continuous Catalyst Regeneration;
- Reactor Effluent Compression and Treating;
- Gas Separation;
- Fractionation;
- Hydrogen Pressure Swing Adsorption (PSA); and
- Support Operations such as unloading and storage of miscellaneous raw materials, product storage, product loading, fuel gas system, steam generation, cooling water system, flare, and routine maintenance, startup, and shutdown activities.

C3P is submitting this GHG permit application to authorize the construction of the PDH unit and other associated activities as described above. Each part of the chemical manufacturing process and associated emissions are identified in the following discussion of the PDH process.

Production Operations

Feed Pre-Treatment

Propane feedstock for the PDH plant will come from outside the battery limits (OSBL) of the Chocolate Bayou complex and will be stored in storage bullets.

Before propane enters the PDH Reaction section of the unit, impurities and moisture are removed. Metals and sulfur compounds are removed via the use of guard beds. Moisture is removed from the propane feed via the use of feed driers. A small volume of waste water will be generated from the regeneration of the feed driers. This waste water will be hard-piped and transferred to the existing Ascend Chocolate Bayou waste water treatment plant.

Heavies Removal

After Feed Pre-treatment, propane feed is exchanged with hot reactor effluent to pre-heat the feed. The propane feed is then routed to a series of two Depropanizer Columns. In the first Depropanizer Column, heavier components (primarily butane and heavier) are drawn off as bottom fraction (C4+ fraction). The second Depropanizer Column is subsequently utilized to separate butanes from the heavier components. Butanes will be stripped in this second Depropanizer Column and sold as product. Other residual from the bottom of the second Depropanizer column (C5+) will be stored as liquids. The storage tank for these liquids (FIN 320T-102) is vented to the flare (EPN PDH-FLARE). These liquids are subsequently loaded into tank trucks and transported off-site for disposal.

The overhead product (propane) from the first and second Depropanizer Columns is then cooled and routed to the Separation Section (Coldbox) of the process, where it is combined with recycle hydrogen and is exchanged against cold reactor effluent prior to use in the PDH Reaction section.

PDH Reaction

The cooled propane feed from the Separation Section (Coldbox) is routed to the PDH Reaction section. It is heated via the feed exchanger and then routed to the reactors.

The dehydrogenation of propane to propylene takes place in two parallel reaction trains. Each reaction train consists of four reactors in series which utilize a proprietary catalyst. Each of these reactors will have an associated gas-fired heater. The heaters are identified as the Charge Heater (EPNs PDH-H101 and PDH-H201) prior to the first reactor, Inter-Heater 1 (EPNs PDH-H102 and PDH-H202) prior to the second reactor, Inter-Heater 2 (EPNs EPNs PDH-H103 and PDH-H203) prior to the third reactor, and Inter-Heater 3 (EPNs PDH-H104 and PDH-H204) prior to the fourth reactor.

In addition to the desired propylene product, other hydrocarbons such as ethane, ethylene, and methane are also produced. Effluent from each reaction train is routed to the Reactor Effluent Compression and Treating section of the plant.

Emissions of NO_X produced in the charge heater and three inter-heaters on each reactor train will be controlled via the use of ultra-low NO_X burners and selective catalytic reduction (SCR).

Continuous Catalyst Regeneration

The continuous catalyst regeneration (CCR) section of the PDH process is designed to replenish the catalyst’s activity in a continuous operation.

In the Regeneration Towers, three of the four basic steps of the catalyst regeneration process take place. These are (1) burning of the coke, (2) removal of excess moisture, and (3) oxidation and dispersion of metal promoters. The coke burn step is a complete burn, leaving no VOCs or CO to be emitted to the atmosphere.

After leaving the Regeneration Tower, catalyst flows by gravity into a hopper. In the hopper, nitrogen and oxygen atmosphere from the Regeneration Tower is purged from the catalyst and the atmosphere is changed to a hydrogen atmosphere. The catalyst then flows by gravity to a lift engager, where high purity hydrogen is used to pneumatically lift the catalyst back to the top of Reactor No. 1.

At the top of Reactor No. 1, the catalyst enters the upper portion of the reactor. As it enters the upper portion of the reactor, the platinum on the catalyst is changed from its oxidized state (resulting from the carbon burning in the Regeneration Tower) to its reduced state by reaction with high temperature hydrogen, thus completing the fourth step of the catalyst regeneration process.

Reactor Effluent Compression and Treating

The hot reactor effluent from the fourth reactor is cooled with the reactor feed exchanger and compressed. It is then sent through a reactor effluent drier before entering the separation section. The dried, compressed reactor effluent is then sent to a cryogenic separation system to separate hydrogen and methane from heavier hydrocarbons. A heavy aromatic solvent (FIN 320T-101) is occasionally injected into this section of the process to minimize reactor effluent and reactor effluent compressor cooler fouling. Spent solvent generated as a result of this solvent injection is stored (FIN 320T-103) and subsequently loaded into tank trucks for off-site disposal. The heavy aromatic solvent tank and spent solvent tank both vent to the unit flare (EPN PDH-FLARE).

Gas Separation (Coldbox)

In the dehydrogenation process, hydrogen (H_2) is formed as a result of the main reaction of propane. The purpose of the Gas Separation section is to remove this hydrogen as well as methane from the heavier hydrocarbons by cryogenic gas separation (Coldbox).

The Coldbox is utilized to separate uncondensable process gas components like hydrogen and methane from the propane and propylene hydrocarbon phase by partial condensation. The hydrocarbon phase is condensed. The hydrogen and methane remain in the gas phase. Hydrocarbons condensed in the Gas Separation step are sent to the Fractionation section of the PDH unit. The gas phase from this step is sent to the Hydrogen PSA Unit.

Fractionation

Lower hydrocarbons such as ethane and ethylene are also formed as by-products of the PDH process and condensed in the Coldbox. The purpose of the Fractionation section of the PDH unit is to remove these by-products from the desired propylene product by distillation. This section of the PDH unit consists of a Selective Hydrogenation Process (SHP) reactor (for C_3 diene removal), Deethanizer, Demethanizer, and Propylene/Propane Splitter.

The purpose of the SHP reactor is to remove C_3 dienes from the hydrocarbon liquid phase from the Coldbox. This removal is accomplished by adding hydrogen from the PSA unit to selectively convert these C_3 dienes to propylene.

In the Deethanizer, ethane, ethylene, and other light components are removed from the hydrocarbon liquid phase from the SHP reactor. The overhead vapors from the Deethanizer go to the Demethanizer. The bottom product from the Deethanizer, consisting of a mixture of propylene and propane goes to the Propylene/Propane Splitter.

In the Demethanizer, lighter components (primarily CH_4) are removed in the overhead stream and blended into the Fuel Gas system of the PDH unit. Heavier components (primarily ethane and ethylene) from the bottom of the Demethanizer column are transported via pipeline to customers.

In the Propane/Propylene Splitter, propane is separated from the desired propylene product. Propylene is obtained as overhead product of the C3 Splitter. Propane and traces of higher boiling components are removed as the bottom product of this splitter. This bottom product is recycled to the first Depropanizer Column in the Feed Pre-Treatment section of the PDH unit.

Hydrogen Pressure Swing Adsorption (PSA)

The Hydrogen Pressure Swing Adsorption Unit takes feed from the Gas Separation section of the plant and produces saleable H_2 gas. This high-purity H_2 gas is also utilized in the CCR section of the plant as described previously and in the SHP section of the plant. The remaining tail gas from the PSA unit is blended into the Fuel Gas system of the PDH unit.

Raw Material and Product Storage

Primary feeds to the PDH process include propane, ammonia for the SCR Units, solvent injection for the Compression section of the plant, and caustic. Propane feed is stored in storage bullets prior to introduction into the PDH process. There will be no routine venting from these bullets. Each will be equipped with Pressure Safety Valves (PSVs) that will vent to the flare. Anhydrous ammonia will be received via pipeline and stored in a pressurized storage vessel, with PSV venting to the flare. Organic liquids used in the process will be stored in vertical fixed roof tanks that vent to the PDH flare. Fresh caustic will be stored in vertical fixed roof tanks. Other chemicals on-site are those used for boiler feed water treatment and cooling water treatment. These are either stored in atmospheric tanks or isotainers.

Propylene product will be stored in a sphere and sold to customers. C_2 and H_2 products will also be transferred off-site via pipeline. C_4 products will be stored in spheres and loaded into barges under a contract with Ascend. Barge loading and the flare associated with this barge loading is authorized by PBR Registration Number 77064 issued to Ascend. C_5+ heavies from the process will be stored in a horizontal tank that vents to the PDH flare.

Raw Material and Product Loading/Unloading

VOCs unloaded at the PDH plant will be received via tank truck. Dry couplings or the equivalent will be used and unloading emissions controlled by the PDH flare. With the exception of C_4, all products will be transferred from the PDH plant via pipeline. C_4 will be loaded into barges as discussed in the previous section.

Fuel Gas System

The Fuel Gas System is utilized to provide fuel for combustion in the two PDH Reaction trains and steam generators. Fuels include natural gas and process fuel gases.

Steam Generation

Two boilers (FINs PDH BOILER 1 and PDH BOILER 2) will be used for Steam Generation at the PDH unit to produce high pressure (HP) steam for various heating purposes in the unit. They will utilize a combination of fuel gas generated by the process and natural gas. Emissions of oxides of nitrogen (NO_X) from these boilers will be controlled via the use of ultra-low NO_X burners and selective catalytic reduction (SCR). Both boilers will vent to a single SCR unit (EPN PDH BOILERS).

Cooling Water System

The PDH unit will utilize a single cooling tower (EPN PDH-CT). Several of the heat exchangers on the loop in VOC service will be operated with a water-side pressure that is less than the process-side pressure. Therefore, the cooling water system is considered to be a potential source of VOC emission as well as particulate matter emissions (PM).

Flare

The PDH plant will utilize one ground flare (EPN PDH-FLARE) for the control of process analyzer vent streams, VOC loading/unloading emissions, and intermittent process vent streams such as the emergency venting of pressure safety valves (PSVs) in the PDH unit. It is also utilized during process clearing and venting for routine maintenance, startup and shutdown.

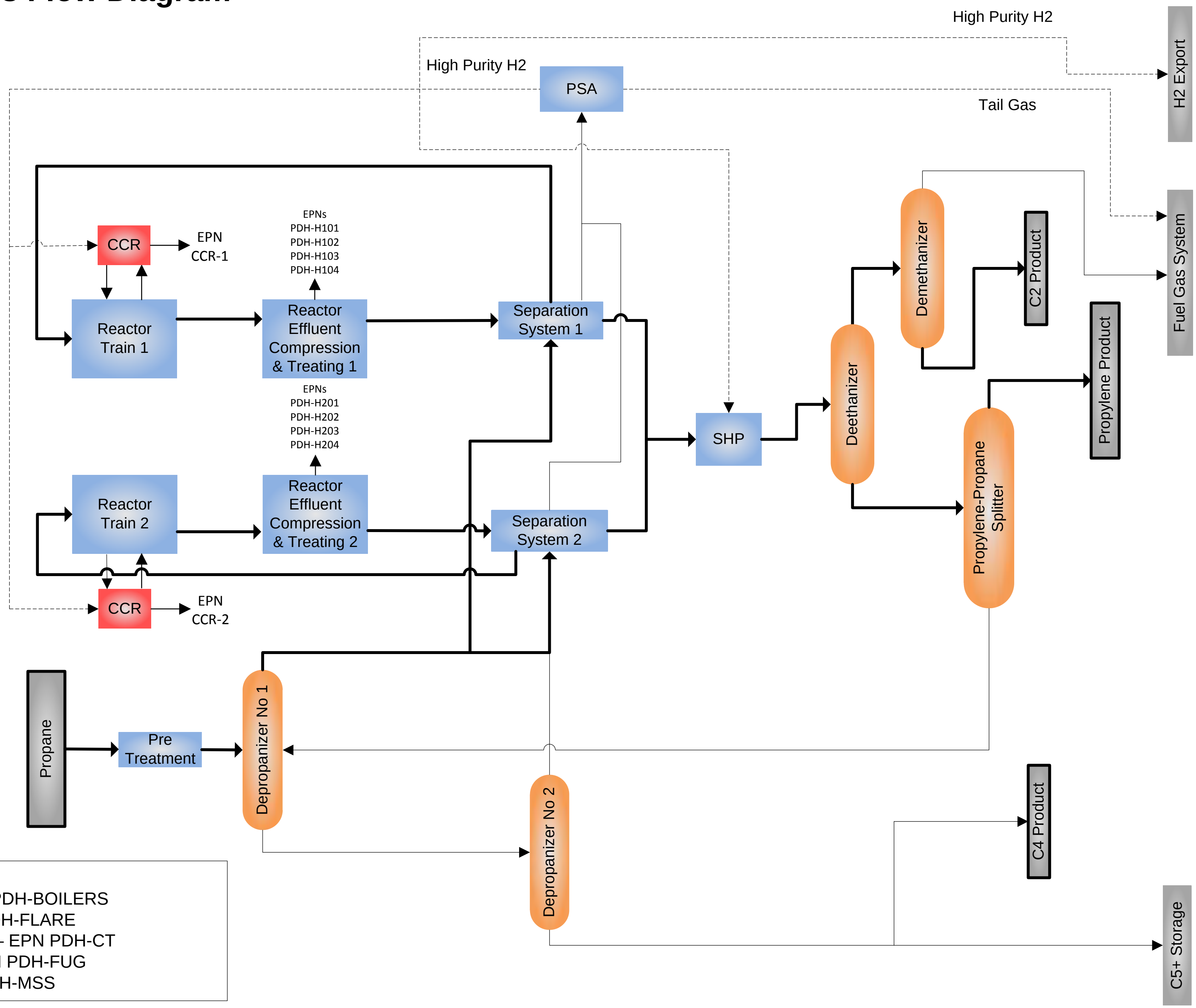
Wastewater Storage and Treatment

The PDH unit will generate three waste water streams. These are from regeneration of the propane feed dryer, regeneration of the reactor effluent dryer, and spent caustic from the CCR vent gas scrubber. As discussed previously, the waste water from all streams will be hard-piped to their ultimate disposition. Waste water from the regeneration of the reactor effluent dryer will be disposed in the existing deepwell disposal at the Ascend Chocolate Bayou plant. The other two waste water streams will be treated in the existing Chocolate Bayou waste water treatment plant.

Routine Maintenance, Startup, and Shutdown Activities

Planned and predictable maintenance, startup and shutdown (MSS) activities at the PDH unit will be conducted in a way that will minimize emissions to the atmosphere. This will generally be accomplished by clearing equipment before line openings or vessel opening. Where feasible, this equipment will be cleared back to the process or routed to the process flare. Additional details are found in the Emissions Data section of this application. These MSS emissions are identified as EPN PDH-MSS.

C3 Petrochemicals LLC - PDH Plant
Process Flow Diagram



Site-wide EPNs
Boilers – EPN PDH-BOILERS
Flare – EPN PDH-FLARE
Cooling Tower – EPN PDH-CT
Fugitives – EPN PDH-FUG
MSS – EPN PDH-MSS

ENVIRON

4 GHG Emission Calculations

The following sections estimate annual emissions of GHGs from various activities in the PDH unit. All backup documentation for these emission calculations are found in Appendix A of this permit application.

4.1 Heaters

Heaters in the reaction sections of the PDH unit will utilize a combination of natural gas and process fuel gas for combustion. The emission calculations for these heaters are based on a representative fuel mixture provided by the PDH technology vendor.

These heaters will be a source of CO_2, CH_4, and N_2O emissions. These emissions are calculated in accordance with the procedures in the Mandatory Greenhouse Gas Reporting rules, 40 CFR 98, Subpart C – General Stationary Fuel Combustion Sources. Equation C-5 is used for calculating CO_2 emissions. CH_4 and N_2O are calculated using Equation C-8b and the emission factors (kg/MMBtu) for natural gas combustion from Table C-2. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules. Sample calculations for the Charge Heater (EPN PDH-H101) are shown below.

CO_2 Emissions

$$CO_2\ (metric\ tons) = \frac{44}{12} x\ Fuel\ x\ CC\ x \frac{MW}{MVC} x\ 0.001$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
CC = Annual carbon content of the gaseous fuel (kg C per kg fuel)
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole)
MVC = Molar volume conversion factor at standard conditions (836.6 scf per kg-mole at 60^o F)
44/12 = Ratio of molecular weights, CO_2 to carbon
0.001= Conversion factor from kg to metric tons

For the Charge Heater (EPN PDH-H101):

$$CO_2 = \frac{44}{12} x\ 726{,}156{,}744\ scf/yr\ x\ 0.753\ x \frac{25.27}{836.6} x\ 0.001 = 60{,}530\ metric\ tons$$

To convert to short tons, for the Charge Heater (EPN PDH-H101):

$$60{,}530\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 66{,}722\ short\ tons/yr$$

CH_4 Emissions

$$CH_4\ (metric\ tons) = \ 1\ x\ 10^{-3}\ x\ Fuel\ x\ EF$$

Where:
CH_4 = Annual emissions from the combustion of natural gas (metric tons)
Fuel = Annual natural gas usage (MMBtu)
EF = Fuel-specific emission factor from Table C-2, 0.001 kg/MMBtu for CH_4
1×10^{-3} = Conversion factor from kilograms to metric tons

For the Charge Heater (EPN PDH-H101):

$$CH_4 = 1\ x\ 10^{-3}\ x\ 1{,}105{,}773\,\frac{MMBtu}{yr}\ x\ 0.001\,\frac{kg}{MMBtu} = 1.1\ metric\ tons/yr$$

To convert metric tons to short tons, for the Charge Heater (EPN PDH-H101):

$$1.1\ metric\ tons\ x\ \frac{1.1023\ short\ tons}{metric\ ton} = 1.2\ short\ tons/yr$$

N_2O Emissions

$$N_2O\ (metric\ tons) = \ 1\ x\ 10^{-3} x\ Fuel\ x\ EF$$

Where:
N_2O= Annual emissions from the combustion of natural gas (metric tons)
Fuel = Annual natural gas usage, (MMBtu)
EF = Fuel-specific emission factor from Table C-2, 0.0001 kg/MMBtu for N_2O
1×10^{-3} = Conversion factor from kilograms to metric tons

For the Charge Heater (EPN PDH-H101):

$$N_2O = 1\ x\ 10^{-3}\ x\ 1{,}105{,}773\ \frac{MMBtu}{yr}\ x\ 0.0001\,\frac{kg}{MMBtu} = 0.11\ metric\ tons/yr$$

To convert to short tons, for the Charge Heater (EPN PDH-H101):

$$0.11\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 0.1\ short\ tons/yr$$

CO_2e Emissions

To determine CO_2e emissions, the annual rate of CO_2, CH_4, and N_2O emissions are multiplied by the Global Warming Potential for each compound.

$$CO_2e = (CO_2\ emissions\ x\ GWP) + (CH_4\ emissions\ x\ GWP) + (N_2O\ emissions\ x\ GWP)$$

Where:

GWP for CO_2 = 1

GWP for CH_4 = 21

GWP for N_2O = 310

For the Charge Heater (EPN PDH-H101):

$$CO_2e = (66{,}722\ short\ tons\ x\ 1) + (1.2\ short\ tons\ x\ 21) + (0.1\ short\ tons\ x\ 310)$$
$$= 66{,}786\ short\ tons/yr$$

4.2 Boilers

Boilers for the PDH unit will utilize a combination of natural gas and process fuel gas for combustion. The emission calculations for these boilers are based on a representative fuel mixture provided by the PDH technology vendor.

Boilers for the PDH unit (FINs PDH BOILER 1 and PDH BOILER 2) will be a source of CO_2, CH_4, and N_2O emissions. CO_2 emissions are calculated in accordance with the procedures in the Mandatory Greenhouse Gas Reporting rules, 40 CFR 98, Subpart C – General Stationary Fuel Combustion Sources, using Equation C-5. CH_4 and N_2O are calculated in accordance with the procedures in the Mandatory Greenhouse Gas Reporting rules, 40 CFR 98, Subpart C – General Stationary Fuel Combustion Sources, using Equation C-8b and the emission factors (kg/MMBtu) for natural gas combustion from Table C-2. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules. Sample calculations for FIN PDH BOILER 1 are shown below.

CO_2 Emissions

$$CO_2\ (metric\ tons) = \frac{44}{12} x\ Fuel\ x\ CC\ x \frac{MW}{MVC} x\ 0.001$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons)

Fuel = Annual volume of the gaseous fuel combusted (scf)

CC = Annual carbon content of the gaseous fuel (kg C per kg fuel)

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole)

MVC = Molar volume conversion factor at standard conditions (836.6 scf per kg-mole at 60^o F)

44/12 = Ratio of molecular weights, CO_2 to carbon

0.001 = Conversion factor from kg to metric tons

For BOILER 1:

$$CO_2 = \frac{44}{12}\ x\ 1{,}479{,}212{,}357\ \frac{scf}{yr}\ x\ 0.797\ x\ \frac{28.96}{836.6}\ x\ 0.001 = 149{,}573\ metric\ tons$$

To convert to short tons, for BOILER 1:

$$149{,}573\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 164{,}874\ short\ tons/yr$$

CH_4 Emissions

$$CH_4\ (metric\ tons) = 1\ x\ 10^{-3}\ x\ Fuel\ x\ EF$$

Where:
CH_4 = Annual emissions from the combustion of natural gas (metric tons)
Fuel = Annual natural gas usage (MMBtu)
EF = Fuel-specific emission factor from Table C-2, 0.001 kg/MMBtu for CH_4
1 x 10^{-3} = Conversion factor from kilograms to metric tons

For BOILER 1:

$$CH_4 = 1\ x\ 10^{-3}\ x\ 2{,}522{,}880\ \frac{MMBtu}{yr}\ x\ 0.001\ \frac{kg}{MMBtu} = 2.52\ metric\ tons$$

To convert metric tons to short tons, for BOILER 1:

$$2.52\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 2.8\ short\ tons$$

N_2O Emissions

$$N_2O\ (metric\ tons) = 1\ x\ 10^{-3}\ x\ Fuel\ x\ EF$$

Where:
N_2O= Annual emissions from the combustion of natural gas (metric tons)
Fuel = Annual natural gas usage (MMBtu)
EF = Fuel-specific emission factor from Table C-2, 0.0001 kg/MMBtu for N_2O
1 x 10^{-3} = Conversion factor from kilograms to metric tons

For BOILER 1:

$$N_2O = 1\ x\ 10^{-3}\ x\ 2{,}522{,}880\ \frac{MMBtu}{yr}\ x\ 0.0001\frac{kg}{MMBtu} = 0.25\ metric\ tons$$

To convert to short tons, for BOILER 1:

$$0.25\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 0.3\ short\ tons$$

CO_2e Emissions

To determine CO_2e emissions, the annual rate of CO_2, CH_4, and N_2O emissions are multiplied by the Global Warming Potential for each compound.

$$CO_2e = (CO_2\ emissions\ x\ GWP) + (CH_4\ emissions\ x\ GWP) + (N_2O\ emissions\ x\ GWP)$$

Where:
GWP for CO_2 = 1
GWP for CH_4 = 21
GWP for N_2O = 310

For BOILER1:

$$CO_2e = (164{,}874\ short\ tons\ x\ 1) + (2.8\ short\ tons\ x\ 21) + (0.3\ short\ tons\ x\ 310) = 165{,}018\ short\frac{tons}{yr}$$

4.3 Process Flare

The process flare will use natural gas for the flare pilots and for purge gas. Other routine combustion will include purge lines from process analyzers and control of VOC emissions from filling of VOC storage tanks.

The PDH unit process flare (EPN PDH-FLARE) will be a source of CO_2, CH_4, and N_2O emissions. Emissions from this flare are calculated in accordance with the procedures in the Mandatory Greenhouse Gas Reporting rules, 40 CFR 98, Subpart Y – Petroleum Refineries. CO_2 emissions are calculated by using Equation Y-1a, CH_4 emissions calculated using Equation Y-4, and N_2O emissions calculated using Equation Y-5. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules. Sample calculations for the process flare are shown below.

CO_2 Emissions

$$CO_2 = 0.98\ x\ 0.001\ x\ \frac{44}{12}\ x\ \ Flare\ x\ \frac{MW}{MVC}\ x\ CC$$

Where:
CO_2 = CO_2 mass emissions, metric tons/yr
0.98 = Assumed combustion efficiency of the flare
0.001 = Unit conversion factor (metric tons/kilogram)
44/12 = Ratio of molecular weights, CO_2 to carbon
Flare = Volume of flare gas combusted, scf/yr
MW = Average molecular weight of the flare gas combusted (kg/kg-mole)
MVC = Molar volume conversion factor (836.6 scf/kg-mole at 60^{o} F and 14.7 psia)
CC = Average carbon content of the flare gas, kg C/kg flare gas

For routine emissions from the flare (purge gas and flare pilots):

$$CO_2 = 0.98\ x\ 0.001\ x \frac{44}{12} x\ 803{,}000\ x \frac{29.3}{836.6} x\ 0.750 = 75.8\ metric\ tons$$

To convert to short tons, for the process flare:

$$75.8\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 83.5\ short\ tons$$

CH_4 Emissions

$$CH_4 = \ (CO_2\ x\ EmF_{CH4}/EmF) + CO_2\ x \frac{0.02}{0.98} x \frac{16}{44} x\ F_{CH4}$$

Where:
CH_4 = CH_4 mass emissions, metric tons/yr
CO_2 = CO_2 mass emissions, metric tons/yr
EmF_{CH4} = Default CH_4 emission factor for "Petroleum Products" from Table C-2 of subpart C of 40 CFR 98, kg CH_4/MMBtu
EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu
0.02/0.98 = Correction factor for flare combustion efficiency
16/44 = Correction factor ration of the molecular weight of CH_4 to CO_2
F_{CH4} = Default weight fraction of carbon in the flare gas prior to combustion that is contributed by methane, 0.4 kg C in methane / kg C in flare gas

For routine emissions from the flare (purge gas and flare pilots):

$$CH_4 = (75.8\ x\ 0.001/60) + 75.8\ x\ \frac{0.02}{0.98}\ x\ \frac{16}{44}\ x\ 0.4 = 0.23\ metric\ tons$$

To convert to short tons, for the process flare:

$$0.23\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 0.25\ short\ tons$$

N_2O Emissions

$$N_2O = CO_2\ x\ EmF_{N2O}/EmF$$

Where:
N_2O = Nitrous oxide mass emissions, metric tons/yr
CO_2 = CO_2 mass emissions, metric tons/yr
EmF_{N2O} = Default N_2O emission factor for "Petroleum Products" from Table C-2 of subpart C of 40 CFR 98, kg N_2O/MMBtu
EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu

For routine emissions from the flare (purge gas and flare pilots):

$$N_2O = 75.8\ x\ \frac{0.0001}{60} = 1.3x10^{-4}\ metric\ tons$$

To convert to short tons, for the process flare:

$$1.3x10^{-4}\ metric\ tons\ x\ 1.1023\ \frac{short\ tons}{metric\ ton} = 1.4x10^{-4}\ short\ tons$$

CO_2e Emissions

To determine CO_2e emissions, the annual rate of CO_2, CH_4, and N_2O emissions are multiplied by the Global Warming Potential for each compound.

$$CO_2e = (CO_2\ emissions\ x\ GWP) + (CH_4\ emissions\ x\ GWP) + (N_2O\ emissions\ x\ GWP)$$

Where:
GWP for CO_2 = 1
GWP for CH_4 = 21
GWP for N_2O = 310

For the purge gas and pilots on the process flare (EPN PDH-FLARE):

$$CO_2e = (83.5\ short\ tons\ x\ 1) + (0.25\ short\ tons\ x\ 21) + (1.4x10^{-4}\ short\ tons\ x\ 310) = 89\ short \frac{tons}{yr}$$

4.4 Process Fugitives

C3P has provided details pertaining to fugitive emissions components (EPN PDH-FUG) including:

- An estimated count of valves, pumps, compressors, flanges/connectors and sampling connections; and

- The service of those components.

TCEQ methodology is used to estimate fugitive emissions.[3] Specifically, SOCMI without ethylene emission factors are used to estimate uncontrolled emissions. Controlled emissions are estimated using TCEQ-specified control efficiencies for the 28VHP/28CNTQ Leak Detection and Repair ("LDAR") programs for components in gas and light liquid service. In addition, C3P will install "leakless" pumps and compressors. Therefore, 100% control was applied to fugitive emissions from all pumps and compressors. Using this approach, controlled emissions are estimated as shown in Appendix A.

The chemical composition and concentration of each process stream was obtained from proprietary process simulation provided by the technology licensor and C3P. The output from this process simulation was used to estimate the speciation of fugitive emissions. Actual emissions of the various chemical constituents may vary from those represented in this air preconstruction permit application.

The plant will utilize a number of Pressure Safety Valves (PSVs) in the process. All PSVs in GHG service will relieve to the flare or will be equipped with a rupture disk and pressure sensing device to monitor for disk integrity. Consequently, 100% control for fugitive emissions from PSVs was applied.

[3] Texas Commission on Environmental Quality, "Emissions Factors for Equipment Leak Fugitive Components," Addendum to RG-360A, Table 3 (January 2008) (http://www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/ef_elfc.pdf).

4.5 CCR Vents

The PDH Plant will have two continuous process vents to atmosphere (EPN CCR-1 and EPN CCR-2). Annual GHG emission calculations are based on the following:

- Exhaust flow rate of 0.84 MMscf/day;
- 8,760 annual operating hours; and
- Volume percentages of CO_2 provided by C3P.

Annual emissions of GHGs from EPN CCR-1 are calculated using the following equations:

$$Annual\ CO_2 Emissions\ (short\ tons/yr) = (12.26\%\ CO_2) \times (0.84\ MMscf/day) \div (24\ hr/day) \times (10^6\ scf/MMscf) \times (0.1234\ lb\ CO_2/ft^3) \times (8760\ hr/yr) \div (2000\ lb/ton) = 2{,}318\ short\ tons\ CO_2/yr$$

Backup documentation for the emissions from CCR vents is found in Appendix A.

4.6 Routine Startup, Shutdown and Maintenance Emissions

Emissions due to scheduled MSS have been estimated using the total volume displaced when a unit/equipment is under MSS. For the reactor and fractionation sections, emissions are based on the total volume purged to the flare, VOC content of the purged volume and physical parameters such as maximum operating pressure and temperature. Plant shutdown will likely occur every 18 months. For the purpose of estimating MSS emissions, it is conservatively assumed that one plant shutdown occurs per calendar year. During MSS events, equipment will be cleared of all gas or liquids by returning to the process, de-pressured to the flare as feasible, and then opened to the atmosphere.

The process flare for the PDH unit will be used to control emissions from MSS activities. During MSS, this flare (EPN PDH MSS) will be a source of CO_2, CH_4, and N_2O emissions. Emissions from this flare are calculated in accordance with the procedures in the Mandatory Greenhouse Gas Reporting rules, 40 CFR 98, Subpart Y – Petroleum Refineries. CO_2 emissions are calculated by using Equation Y-1a, CH_4 emissions calculated using Equation Y-4, and N_2O emissions calculated using Equation Y-5. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules. For sample calculations, see the discussion of routine flare emissions.

Backup documentation for flare MSS emissions calculations is found in Appendix A.

5 Prevention of Significant Deterioration Applicability

When constructed, the C3P PDH plant will be on land owned by Ascend Performance Materials Texas, Inc. (Ascend) at its existing Chocolate Bayou (CHB) Chemical Manufacturing Complex. CHB is an existing major source of CO, PM, NO_X and SO_2. The PDH plant will be subject to PSD permitting for NO_X, CO, PM, PM_{10}, $PM_{2.5}$. Emissions from the C3P PDH plant will also exceed 75,000 tons/year of CO_2e. Per Step 2 of the Greenhouse Gas Tailoring Rule[4], for permits issued on or after July 1, 2011, PSD applies for GHGs if the source is otherwise subject to PSD (for another regulated pollutant), and the source has a GHG PTE equal to or greater than 75,000 TPY CO_2e. Construction of the C3P PDH plant will constitute a major modification of an existing major source and PSD is triggered for GHG emissions. TCEQ PSD netting tables 1F and 2F detailing the GHG emission increase from the PDH plant are found in Appendix B.

A separate air preconstruction permit application has been submitted to the Texas Commission on Environmental Quality (TCEQ) to authorize emissions of all regulated air pollutants except for GHGs. This TCEQ permit application is consistent with the requirements in Title 30 of the Texas Administrative Code (30 TAC) Chapter 116, Subchapter B, Division 1.

The purpose of this application is to obtain air quality permit authorization from EPA to authorize GHG emissions from the proposed new PDH plant since the Texas Commission on Environmental Quality (TCEQ) has not submitted the required SIP revisions to EPA and has not implemented a PSD permitting program for GHGs.

[4] 75 FR 31514 (June 3, 2010)

6 Best Available Control Technology (BACT)

As required by 40 CFR §52.21(j), Best Available Control Technology (BACT) must be demonstrated for new and modified emission sources for which a significant net increase will occur. BACT is defined as follows:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

In the EPA guidance document entitled *PSD and Title V Permitting Guidance for Greenhouse Gases*, dated March 2011, EPA recommends the use of the Agency's five-step "top-down" process to determine BACT for greenhouse gases (GHGs). This top-down process calls for the identification of all available control technologies for a given pollutant and the ranking of these technologies in descending order of control effectiveness. The applicant must then evaluate the highest-ranked option and the top-ranked option(s) should be established as BACT unless it is demonstrated that the technical considerations, or energy, environmental, or economic impacts and other costs justify a conclusion that the top-ranked technology is not achievable. If the most effective control strategy is eliminated, then the next most effective control should be evaluated until an option is selected as BACT. BACT cannot be less stringent than any applicable standard of performance under New Source Performance Standards (NSPS); however EPA has not promulgated any NSPS that contain emissions limits for GHGs.

EPA has divided the process of determining BACT into five steps:

Step 1: Identify all available control technologies
Step 2: Eliminate technically infeasible options
Step 3: Rank remaining control technologies

Step 4: Evaluate economic, energy and environmental impacts
Step 5: Select the BACT

The five-step BACT process will be applied to each GHG emission source in the PDH plant. These emission sources include:

- Process heaters;
- Boilers;
- Continuous catalyst regeneration (CCR) vents;
- Process flare; and
- Fugitive emission components

C3P searched the EPA RACT/BACT/LAER Clearinghouse (RBLC) database to assist in the identification of potential GHG emission control technologies. The results of this RBLC search are included in Appendix D of this application.

C3P also compared the performance of GHG-emitting sources in this application to other similar sources in Texas subject to GHG PSD permitting by EPA Region 6. The results of this comparison are found in the benchmarking tables included in Appendix E of this application.

6.1 BACT for Heaters

As mentioned previously in this permit application, the reaction section of the PDH plant will consist of two identical reaction trains, each utilizing a series of four process heaters. These heaters will utilize a combination of natural gas and process fuel gas. Per the PDH technology vendor, these heaters will be designed and operated to achieve a maximum thermal efficiency of 90% without SCR. Since the PDH plant will utilize SCR for the control of NO_X emissions, the thermal efficiency achieved in practice may be reduced to 87%.

6.1.1 Step 1: Identify All Available Control Technologies

Other than Carbon Capture and Sequestration (CCS) which is separately addressed in Appendix C, the primary GHG control options available for combustion units are the selection of energy efficient design to maximize thermal efficiency combined with the implementation of operation and maintenance procedures to ensure ongoing operation of the combustion source in an energy-efficient manner. The following lists those design elements and operating and maintenance practices considered to maximize energy efficiency of the process heaters.

- Use of Low Carbon Fuels – Selection of low carbon fuels in order to limit the amount of CO_2 emissions produced per unit of heat input.

- Heater Design – Good design measures in order to maximize equipment efficiency.

- Heater Air/Fuel Control – Continuous monitoring of oxygen concentration in the flue gas to be used to control excess air for optimal efficiency.

- Periodic Tune-up – Periodic tune-ups of the heaters to maintain maximum efficiency.

6.1.2 Step 2: Eliminate Technically Infeasible Options

All of the options in Step 1 are considered technically feasible for controlling GHG emissions from the process heaters.

6.1.3 Step 3: Rank Remaining Control Technologies

The following reductions in GHG emissions can be achieved by the technologies listed below[5]:

- Use of Low Carbon Fuels – up to 100% for fuels containing no carbon
- Heater Design – 10%
- Heater Air/Fuel Control – 5-25%
- Periodic Tune-up – 2-10%

6.1.4 Step 4: Evaluate Economic, Energy and Environmental Impacts

- Use of Low Carbon Fuels – Combustion of any carbon containing fuel will produce GHG emissions. Of the fuels typically used by industrial processes (coal, fuel oil, natural gas, and process fuel gas), natural gas is the lowest carbon fuel that can be burned. Fuels used by the proposed PDH unit include natural gas and process fuel gas. The process fuel gas generated by the PDH process includes PSA tail gas, Deethanizer overheads, and Demethanizer overheads. The alternative means for disposing of this PSA tail gas, Deethanizer overheads, and Demethanizer overheads is destruction in the process flare, which would result in the same amount of GHG emissions. If the process offgases are flared, more natural gas would be required for the heaters to replace the fuel value of these offgases. Therefore, using them as fuel is an effective means of reducing overall plant GHG emissions.

- Heater Design – New heaters can be designed with a number features to improve efficiency by minimizing heat loss and increasing overall thermal efficiency. Operating a heater at near steady state conditions allows it to achieve maximum efficiency. Design features that improve overall thermal efficiency include efficient burners, and refractory and insulation materials on surfaces to minimize heat loss.

- Heater Air/Fuel Control – Complete combustion can be achieved with the use of 2-3% oxygen. Controlling the air to fuel ratio to maintain this oxygen level in a heater is effective in reducing emissions from overuse of excess air. This level can be maintained with the use of exhaust gas oxygen analyzers, which provide real-time readings of oxygen levels in the exhaust gas.

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[5] EPA, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers,* pg. 49-59 (June 2008).

- Periodic Tune-up – These periodic tune-ups of the heaters include:
    - Calibration of the fuel gas flow meters
    - Preventive maintenance check of excess oxygen analyzers
    - Cleaning of burner tips as needed
    - Cleaning of convection section as needed

6.1.5 Step 5: Select BACT

C3P will utilize all of the technologies listed in Step 4. The heater design and operation/maintenance procedures and technologies are listed below.

- Use of a combination of low carbon fuels. A combination of PSA tail gas, Deethanizer overheads, Demethanizer overheads and natural gas will be fired in the PDH heaters. This will result in lower GHG emissions compared to burning 100% natural gas and disposing of the process offgases in the process flare.

- Good heater design to maximize heat transfer efficiency to evenly heat the feed and reduce heat loss. Insulating material such as ceramic fiber blankets will be used where feasible on all heater surfaces.

- Install, utilize and maintain a continuous air/fuel control system to maximize combustion efficiency of each heater.

- Preventive maintenance of the air/fuel control system.

- Monitor the excess oxygen in the stack of each heater.

- Conduct periodic heater tune-ups as described in Step 4.

- Inspect flame pattern and adjust burners to optimize flame pattern at least annually.

A summary of the proposed work practices, monitoring, recordkeeping, and reporting for these sources is included in Appendix F of this application.

6.2 BACT for Boilers

As mentioned previously in this permit application, the PDH plant will utilize two gas-fired boilers to generate steam required by the propylene manufacturing process. These boilers will utilize a combination of natural gas and process fuel gas. They will be designed and operated to achieve a thermal efficiency of 82%

6.2.1 Step 1: Identify All Available Control Technologies

Other than Carbon Capture and Sequestration (CCS) which is separately addressed in Appendix C, the primary GHG control options available for combustion units are the selection of energy efficient design to maximize thermal efficiency combined with the implementation of operation and maintenance procedures to ensure ongoing operation of the combustion source in an energy-efficient manner. The following lists those design elements and operating and maintenance practices considered to maximize energy efficiency of the boilers.

- Use of Low Carbon Fuels - Selection of low carbon fuels in order to limit the amount of CO_2 emissions produced per unit of heat input.
- Boiler Design – Good design measures in order to maximize equipment efficiency.
- Good Combustion Practices – Operating the boilers using optimum amounts of excess air to achieve maximum combustion efficiency.
- Routine Boiler Maintenance – Conduct regular preventive maintenance on the boilers including regular inspections, cleanings, and calibrations.

6.2.2 Step 2: Eliminate Technically Infeasible Options

All of the options in Step 1 are considered technically feasible for controlling GHG emissions from the boilers.

6.2.3 Step 3: Rank Remaining Control Technologies

The following reductions in GHG emissions can be achieved by the technologies listed below[6]:

- Use of Low Carbon Fuels – up to 100% for fuels containing no carbon
- Boiler Design – 6-26%
- Routine Boiler Maintenance – up to 10%
- Good Combustion Practices – 1% for every 15% reduction in excess air

6.2.4 Step 4: Evaluate Economic, Energy and Environmental Impacts

- Use of Low Carbon Fuels – Combustion of any carbon-containing fuel will produce GHG emissions. Of the fuels typically used by industrial processes (coal, fuel oil, natural gas, and process fuel gas), natural gas is the lowest carbon-containing fuel that can be burned. Fuels used by the proposed PDH unit include natural gas and process fuel gas. The process fuel gas generated by the PDH process includes PSA tail gas, Deethanizer overheads, and Demethanizer overheads. The alternative means for disposing of this PSA tail gas, Deethanizer overheads, and Demethanizer overheads is destruction in the process flare, which would result in the same amount of GHG emissions. If the process offgases are flared, more natural gas would be required for the boilers to replace the fuel value of these offgases. Therefore, using them as fuel is an effective means of reducing overall plant GHG emissions.

[6] *Ibid.*

- Boiler Design – New boilers can be designed with a number of features to improve efficiency by minimizing heat loss and increasing overall thermal efficiency. Operating a boiler at near steady state conditions allows it to achieve maximum efficiency. Design features that improve overall thermal efficiency include efficient burners, and refractory and insulation materials on surfaces to minimize heat loss.

- Periodic Tune-up – The periodic tune-ups of the boilers include:
  - Calibration of the fuel gas flow meters
  - Preventive maintenance check of the excess oxygen analyzers
  - Cleaning of the burner tips as needed
  - Cleaning of the convection section as needed

- Good Combustion Practices – Combustion of excess air requires greater heat input to heat the air. By installing monitoring devices to optimize the air-to-fuel ratio, the amount of excess air combusted, as well as GHG emissions, will decrease. For every 15% reduction in excess air, boiler efficiency can be increased by 1%.

6.2.5 Step 5: Select BACT

C3P will utilize all of the technologies listed in Step 4. The boiler design and operation/maintenance procedures and technologies are listed below.

- Use of a combination of low carbon fuels. A combination of PSA tail gas, Deethanizer overheads, Demethanizer overheads and natural gas will be fired in the PDH heaters. This will result in lower GHG emissions compared to burning 100% natural gas and disposing of the process offgases in the process flare.

- Good boiler design to maximize heat transfer efficiency to evenly heat the boiler feed and reduce heat loss. These include:
  - Ultra low NO_X burners with flue gas recirculation
  - Castable refractory on furnace floor over drums
  - 2” refractory tiles over furnace floor tubes
  - 2” rigid insulating block on front and rear walls
  - 2-3” blanket insulation on other exterior surfaces
  - Minimization of steam vents
  - Recovery of hot condensate
  - Minimize draining of condensate
  - Use of an economizer to pre-heat boiler feed water streams
  - Install, utilize and maintain a continuous air/fuel control system to maximize combustion efficiency of each boiler.
  - Metered fuel consumption
  - Monitoring of oxygen in the flue gas
  - Monitoring of CO in the exhaust
  - Monitoring of exhaust temperature
  - Monitoring of fuel temperature

- Preventive maintenance of the air/fuel control system.
- Conduct periodic boiler tune-ups as described in Step 4.
- Inspect flame pattern and adjust burners to optimize flame pattern at least annually.

A summary of the proposed work practices, monitoring, recordkeeping, and reporting for these sources is included in Appendix F of this application.

6.3 BACT for Flares

GHG emissions from the flare (EPN PDH-FLARE) consist primarily of CO_2. Routine emissions are generated from the combustion of the natural gas pilots used to maintain the required minimum heating value and achieve adequate VOC destruction. Other routine vents to the process flare are from process analyzers and VOC storage tanks. The flare also controls VOC emissions from periodic MSS events that require degassing of process equipment and piping.

In addition to normal operation and MSS events, the flare is designed to control emissions from emergency releases. A thermal oxidizer is incapable of handling sudden large volumes of gas which occur during upset conditions, so has not been considered in this analysis.

6.3.1 Step 1: Identify All Available Control Technologies

The only GHG control options for flares or other such control devices are to minimize the quantity and duration of VOC material vented and to design and operate these devices to minimize the natural gas used to maintain the minimum heating value required to achieve adequate destruction. The following lists those design elements and operating practices considered to optimize flare performance and minimize GHG emissions.

- Good Combustion Practices – Operate the flare using flow and composition monitors to optimize the amount of natural gas required for adequate VOC destruction and minimize GHG emissions from combustion.
- Flare Minimization – Minimize the quantity and duration of emissions routed to the flare.
- Flare Design – Good design measures in order to maximize equipment efficiency.

6.3.2 Step 2: Eliminate Technically Infeasible Options

Good combustion practices, flare minimization, and flare design are all considered to be technically feasible options.

6.3.3 Step 3: Rank Remaining Control Technologies

C3P will utilize all design elements and operating practices described in Step 1.

6.3.4 Step 4: Evaluate Economic, Energy and Environmental Impacts

No BACT options are being eliminated in this step.

6.3.5 Step 5: Select BACT

C3P will utilize all of the technologies listed in Step 1. The flare design and operating practices are described in further detail here.

- Good Combustion Practices –
    - Use of flow meters and gas composition monitors on the flare gas lines to improve flare gas combustion and optimize flare combustion efficiency.
    - Continuous monitoring of the flare pilot.
- Flare Minimization –
    - Utilize process offgases as fuel for boilers and heaters
    - Utilize PDH process controls to minimize upset conditions
    - Clear equipment to storage as possible to minimize the quantity of VOC materials vented to the flare during MSS
- Flare Design – C3P proposes to use a ground flare with 11 stages, each with 2 pilots. It will be designed and operated per the requirements of 40 CFR §60.18. It is assumed to achieve 98% destruction removal efficiency (DRE) for organic compounds. This flare will incorporate the latest burner design and combustion temperature control to minimize NO_X formation while, at the same time, maximizing VOC control efficiency.

A summary of the proposed work practices, monitoring, recordkeeping, and reporting for the flare is included in Appendix F of this application.

6.4 BACT for Fugitives

6.4.1 Step 1: Identify All Available Control Technologies

GHG emissions from leaking piping components (process fugitives) from the PDH plant consist of primarily methane from equipment in natural gas service or other fuel gas service. These emissions will constitute a negligible portion of the overall GHG emissions from the C3P PDH plant (approximately 3 tons/year). The following methods are available for reducing these fugitive emissions:

- Leakless Technology Components – Eliminates leaks which eliminates fugitive emissions.
- Leak Detection and Repair (LDAR) Programs – Regular inspection programs, typically used for VOC control, identify and correct leaking components to minimize emissions.
- Audio/Visual/Olfactory (AVO) Monitoring Program – Regular inspection program, typically used for non-VOC control, identifies and corrects leaking components to minimize emissions.

- Remote Sensing Technology – Remotely monitors emissions using technology such as infrared cameras to detect leaks, therefore making it possible to repair the leak quickly, reducing fugitive emissions.

6.4.2 Step 2: Eliminate Technically Infeasible Options

All options in Step 1 are considered technically feasible for controlling process fugitive emissions.

6.4.3 Step 3: Rank Remaining Control Technologies

- Leakless Technology Components – Leakless technologies are 100% effective in eliminating fugitive emissions from the locations where installed. However, because of their high cost, these specialty components are, in practice, selectively applied only as absolutely necessary for toxic or hazardous components.

- AVO Monitoring – AVO detections can be performed very frequently, at lower cost and with less additional manpower and equipment than Method 21 instrument or remote sensing monitoring because it does not require specialized monitoring equipment. AVO monitoring is as effective in detecting significant leaks as Method 21 instrument or remote sensing monitoring if AVO inspections are performed frequently enough. Therefore, for components in methane (natural gas or fuel gas) service, AVO is considered the most preferred technically feasible alternative.

- LDAR Programs – Method 21 instrument monitoring has historically been used to identify leaks in need of repair. However, instrument monitoring requires significant allocation of manpower as compared to AVO monitoring, while AVO is expected to be equally effective at identifying significant leaks.

- Remote Sensing – Remote sensing using infrared imaging has been accepted by EPA as an acceptable alternative to Method 21 instrument monitoring and leak detection effectiveness is expected to be comparable. Although less manpower may be required for remote sensing compared to Method 21 depending on the number of sources, the frequency of monitoring is more limited than AVO because the number of simultaneous measurements will be limited by the availability of the remote sensing equipment.

6.4.4 Step 4: Evaluate Economic, Energy and Environmental Impacts

- Leakless Technology Components – Leakless technologies have not been universally adapted as BACT for emissions from fugitive piping components. This technology alone is not considered effective for control of GHG emissions from fugitive components.

- AVO Monitoring – AVO monitoring, typically used for non-VOC emissions, is expected to be effective in finding leaks, can be implemented at the greatest frequency, and lower cost due to being incorporated into routine operations. AVO monitoring is incorporated into the TCEQ's 28VHP LDAR program for leak detection of odorous and non-VOC constituents.

- LDAR Programs – C3P will use the 28VHP/28CNTQ LDAR programs for fugitive VOC emission control. This program is not designed for GHG monitoring, although detection of VOC leaks will also minimize fugitive GHG emissions. This method is considered less effective than AVO monitoring because it is conducted less frequently. It is also more costly than AVO monitoring.

- Remote Sensing – Economically, remote sensing monitoring has lower cost than Method 21 instrument monitoring, but is still more costly than AVO due to the specialized equipment required for the monitoring. The use of specialized equipment also limits the frequency with which the components can be monitored. Remote sensing is better suited for larger potential emission sources that contain critical fugitive components with the potential for high volume leaks. Remote sensing is not practicable for small fugitive sources, like those found at C3P.

6.4.5 Step 5: Select BACT

The PDH plant will implement the TCEQ's LDAR programs (28VHP/28CNTQ) for VOC control for fugitive components. Pumps, compressors, and agitators in VOC service will be equipped with a shaft sealing system that prevents or detects emissions of VOCs from the seal (i.e. "leakless"). While not specifically designed for control of GHG fugitive emissions, this program will minimize GHG emissions while also controlling VOC emissions. Therefore, C3P's proposed BACT for fugitive components is the TCEQ's 28VHP/28CNTQ LDAR programs.

A summary of the proposed work practices, monitoring, recordkeeping, and reporting for equipment leak fugitives is included in Appendix F of this application.

6.5 BACT for CCR Vents

The continuous catalyst regeneration (CCR) section of the PDH process is designed to replenish the catalyst's activity in a continuous operation by burning off the coke deposits. The CCR vents (one for each reaction section) contain small quantities of CO_2 as a result of this process. These CCR vents are identified as EPN CCR-1 and CCR-2.

6.5.1 Step 1: Identify All Available Control Technologies

Other than Carbon Capture and Sequestration (CCS) which is separately addressed in Appendix C, the only GHG emission control options available for process vents such as the CCR vents are good process design. Therefore, GHG control technologies for the CCR vents are as follows:

- CCR Design – Good design measures in order to maximize equipment efficiency.

6.5.2 Step 2: Eliminate Technically Infeasible Options

All control technologies identified in Step 1 are considered a technically feasible for controlling GHG emissions from the CCR vents.

6.5.3 Step 3: Rank Remaining Control Technologies

No BACT options are being eliminated in this step.

6.5.4 Step 4: Evaluate Economic, Energy and Environmental Impacts

No BACT options are being eliminated in this step.

6.5.5 Step 5: Select BACT

CCR design is considered BACT for the CCR vents. The proprietary technology used by the C3P PDH plant minimizes the coke formation on the catalyst, providing for maximum heat transfer in the catalyst and minimizing associated emissions. Unlike some other PDH process technologies, the CCR section does not require steam-purging of the catalyst prior to regeneration, thus reducing the process consumption of steam. Instead, the CCR system is designed to use small amounts of nitrogen, which eases carbon burning, allowing it to be done at mild conditions. The system achieves complete burn, which eliminates VOC and CO emissions.

7 Other PSD Requirements

7.1 Impacts Analysis

An impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs.*[7]

7.2 GHG Preconstruction Monitoring

A preconstruction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> *EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.*[8]

7.3 Additional Impacts Analysis

The requirements for a PSD additional impact analyses are described in 40 CFR §52.21(o). A Biological and Cultural assessment of the impact of emissions from the proposed PDH plant will be submitted under separate cover to address the potential impairment to soils and vegetation having significant commercial or recreational value that might occur as a result of emissions from this plant. Refined dispersion modeling will also be submitted to the TCEQ to address PSD impacts of the project for other criteria pollutants. Additional PSD additional impacts analysis for GHG emissions are not being provided with this application in accordance with EPA's recommendations:

> *Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and*

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[7] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases at 47-48.

[8] *Id.* at 48.

vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.[9]

[9] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases

Appendix A

GHG Emission Calculations

Table A-1 - Greenhouse Gas Emissions Summary

Source	Estimated Greenhouse Gas Emissions (tpy)			
	CO_2	CH_4	N_2O	Total CO_2e
Reaction Train I	230,077	4.2	0.4	230,296
Reaction Train II	230,077	4.2	0.4	230,296
Boilers	329,748	5.6	0.6	330,037
CCR Vents	4,636			4,636
Process Fugitive Emissions	1.6E-03	0.15		3.1
Flare Routine	165	0.5	2.7E-04	175.1
MSS Controlled (emitted from the Flare)	412	1.2	6.9E-04	438.3
TOTAL	**795,115**	**15.8**	**1.4**	**795,881**
Signficant PSD Emission Level for GHGs				**100,000**

Greenhouse Gas Emission Calculations - Heaters: Reaction Train 1

Fuel Gas Usage - Maximum Hourly and Annual Emissions

Source	EPN	Fuel Flow (scf/yr)	Heat Input (MMBTU/yr)	Annual GHG Emissions (tpy)			
				CO_2	CH_4	N_2O	Total GHG (CO_2e)
Charge Heater	PDH-H101	726,156,744	1,105,773	66,722.4	1.2	0.12	66,785.8
No. 1 Interheater	PDH-H102	776,236,520	1,182,033	71,324.0	1.3	0.13	71,391.7
No. 2 Interheater	PDH-H103	550,877,530	838,862	50,617.0	0.9	0.09	50,665.1
No. 3 Interheater	PDH-H104	450,717,979	686,342	41,413.9	0.8	0.08	41,453.3
TOTAL		**2,503,988,773**	**3,813,009**	**230,077.4**	**4.2**	**0.4**	**230,295.9**

Fuel Type: Fuel Gas for Normal Operations

Component	Weight Percent (%)	HHV (Btu/scf)	MW (kg/kgmol)	Carbon atoms/mole	Carbon Content
Hydrogen	0.041	325	2.02	0	0
Methane	0.276	1011	16.04	1	0.749
Ethane	0.667	1783	30.07	2	0.799
Propane	0.016	2572	44.10	3	0.817
Total	1	1523	25.27		0.753

Notes

Conversions & Emission Factors

8760	hr/yr
2000	lb/ton
0.0001	kg/MMBTU N_2O, from 40 CFR 98 Subpart C, Table C-2
0.001	kg/MMBTU CH_4, from 40 CFR 98 Subpart C, Table C-2
310	GWP for N_2O
21	GWP for CH_4
1	GWP for CO_2
0.1234	density of CO2 (lb/ft^3)at STP from http://www.engineeringtoolbox.com/gas-density-d_158.html
2.20462	lb/kg
0.001	conversion factor from kilograms to metric tons
1.1023	short tons/metric ton

Greenhouse Gas Emission Calculations - Heaters: Reaction Train 2

Fuel Gas Usage - Maximum Hourly and Annual Emissions

Source	EPN	Fuel Flow (scf/yr)	Heat Input (MMBTU/yr)	Annual GHG Emissions (tpy)			
				CO_2	CH_4	N_2O	Total GHG (CO_2e)
Charge Heater	PDH-H101	726,156,744	1,105,773	66,722.4	1.2	0.12	66,785.8
No. 1 Interheater	PDH-H102	776,236,520	1,182,033	71,324.0	1.3	0.13	71,391.7
No. 2 Interheater	PDH-H103	550,877,530	838,862	50,617.0	0.9	0.09	50,665.1
No. 3 Interheater	PDH-H104	450,717,979	686,342	41,413.9	0.8	0.08	41,453.3
TOTAL		**2,503,988,773**	**3,813,009**	**230,077.4**	**4.2**	**0.4**	**230,295.9**

Fuel Type: Fuel Gas for Normal Operations

Component	Weight Percent (%)	HHV (Btu/scf)	MW (kg/kgmol)	Carbon atoms/mole	Carbon Content
Hydrogen	0.041	325	2.02	0	0
Methane	0.276	1011	16.04	1	0.749
Ethane	0.667	1783	30.07	2	0.799
Propane	0.016	2572	44.10	3	0.817
Total	1	1523	25.27		0.753

Notes

Conversions & Emission Factors

8760	hr/yr
2000	lb/ton
0.0001	kg/MMBTU N_2O, from 40 CFR 98 Subpart C, Table C-2
0.001	kg/MMBTU CH_4, from 40 CFR 98 Subpart C, Table C-2
310	GWP for N_2O
21	GWP for CH_4
1	GWP for CO_2
0.1234	density of CO2 (lb/ft^3)at STP from http://www.engineeringtoolbox.com/gas-density-d_158.html
2.20462	lb/kg
0.001	conversion factor from kilograms to metric tons
1.1023	short tons/metric ton

Greenhouse Gas Emission Calculations - Boilers

EPN	FIN	Fuel Flow (scf/yr)	Average Heat Input (MMBTU/yr)	Annual GHG Emissions (tpy)			
				CO_2	CH_4	N_2O	Total GHG (CO_2e)
PDH BOILERS	PDH BOILER 1	1,479,212,357	2,522,880	164,874	2.8	0.3	165,018
	PDH BOILER 2	1,479,212,357	2,522,880	164,874	2.8	0.3	165,018
TOTAL		2,958,424,715	5,045,760	**329,747.7**	**5.6**	**0.6**	**330,037**

Fuel Type: DeC2 Ovhd

Component	Weight Percent (%)	HHV (Btu/scf)	MW (kg/kgmol)	Carbon Atoms/mole	Carbon Content
Hydrogen	0.05%	325	2.016	0	0
Methane	8.17%	1011	16.04	1	0.749
Ethylene	3.27%	1631	28.05	2	0.856
Ethane	87.57%	1783	30.07	2	0.799
Propylene	0.85%	2332	42.08	3	0.856
Propane	0.09%	2572	44.10	3	0.817
Total	100.00%	1720	28.96		0.797

Conversions & Emission Factors

8760	hr/yr
2000	lb/ton
0.0001	kg/MMBTU N_2O, from 40 CFR 98 Subpart C, Table C-2
0.001	kg/MMBTU CH_4, from 40 CFR 98 Subpart C, Table C-2
310	GWP for N_2O
21	GWP for CH_4
1	GWP for CO_2
0.1234	density of CO_2 (lb/ft^3)at STP from http://www.engineeringtoolbox.com/gas-density-d_158.html
2.20462	lb/kg
0.001	conversion factor from kilograms to metric tons
1.1023	short tons/metric ton

Greenhouse Gas Emissions Calculations - CCR Vent Streams

EPN	CCR-1	CCR-2
Exhaust Flow Rate (MMscf/day)	0.84	0.84
Duration (hrs/yr)	8,760	8,760

GHG Concentration in Vent	Volume %
Carbon dioxide	12.26%

GHG Emission Rate (tons/year)		
Carbon dioxide	2,318	2,318

Conversions:		
1 MMscf =	1,000,000	scf
1 g =	1,000	mg
1 m^3 =	35.3147	ft^3
1 day =	24	hours
1 ton =	2,000	pounds
Density of CO_2[1] =	0.123	lb/ft^3

Notes:
[1] Density at standard temperature and pressure (STP) from http://www.engineeringtoolbox.com/gas-density-d_158.html

Greenhouse Gas Emission Calculations - Routine Flare Emissions

EPN	Description	Flow (scf/yr)	Annual GHG Emissions (tpy)			
			CO_2	CH_4	N_2O	Total GHG (CO_2e)
PDH FLARE	Pilots and Purge	803,000	83.5	0.25	1.4E-04	88.8
	Analyzer Vents	4,641	0.6	1.7E-03	9.6E-07	0.6
	Tank 320-T100 vent	18,414	2.1	6.3E-03	3.5E-06	2.2
	Tank 320-T101 vent	7,350	4.2	1.2E-02	7.0E-06	4.4
	Tank 320-T102 vent	205,478	70.1	0.2	1.2E-04	74.5
	Tank 320-T103 vent	7,350	4.2	1.2E-02	7.0E-06	4.4
TOTAL		**1,046,232**	**165**	**0.5**	**2.7E-04**	**175.1**

Natural Gas

Component	Weight Percent (%)	HHV (Btu/scf)	MW (kg/kgmol)	Carbon Atoms/mole	Carbon Content
Nitrogen	1.13%		28.02	0	0.000
Carbon Dioxide	2.16%		44.01	1	0.273
Methane	71.98%		16.04	1	0.749
Ethane	2.70%		30.07	2	0.799
Propane	0.64%		44.10	3	0.817
Isobutane	0.14%		58.10	4	0.827
n-Butane	0.14%		58.10	4	0.827
Isopentane	14.08%		72.15	5	0.832
n-Pentane	7.04%		72.15	5	0.832
Total		1018	29.30		0.750

Analyzer Vents

Component	Weight Percent (%)	HHV (Btu/scf)	MW (kg/kgmol)	Carbon Atoms/mole	Carbon Content
Hydrogen	1.72%		2.016	0	0.000
Nitrogen	24.27%		28.02	0	0.000
Methane	1.10%		16.04	1	0.749
Ethylene	0.04%		28.05	2	0.856
Ethane	0.88%		30.07	2	0.799
Propylene	16.49%		42.08	3	0.856
Propane	48.50%		44.10	3	0.817
Isobutene	0.08%		56.11	4	0.856
n-butane	0.20%		58.10	4	0.827
Isobutane	0.94%		58.10	4	0.827
Benzene	0.10%		78.11	6	0.923
Styrene	5.68%		104.15	8	0.923
Total	100.00%		42.32		0.617

Tank Vents 320-T100

Component	Weight Percent (%)	HHV (Btu/scf)	MW (kg/kgmol)	Carbon Atoms/mole	Carbon Content
Dimethyldisulfide	100.00%		94.2	2	0.255
Total			94.2		0.255

Tank Vents 320-T101 and 320-T103

Component	Weight Percent (%)	HHV (Btu/scf)	MW (kg/kgmol)	Carbon Atoms/mole	Carbon Content
Diethylbenzene	99.00%		134.22	10	0.895
Naphthalene	1.00%		128.20	10	0.937
Total	100%		134.16		0.895

Tank Vents 320-T102

Component	Weight Percent (%)	HHV (Btu/scf)	MW (kg/kgmol)	Atoms/mole	Content
Benzene	100.00%		78.1	6	0.923
Total			78.1		0.923

Conversions & Emission Factors

8760	hr/yr
2000	lb/ton
0.0001	kg/MMBTU N_2O, from 40 CFR 98 Subpart C, Table C-2
0.001	kg/MMBTU CH_4, from 40 CFR 98 Subpart C, Table C-2
310	GWP for N_2O
21	GWP for CH_4
1	GWP for CO_2
0.001	conversion factor from kilograms to metric tons
1.1023	short tons/metric ton

Greenhouse Gas Emission Calculations - Flare Emissions During Maintenance, Startup, and Shutdown

EPN	Description	Flow (scf/yr)	Annual GHG Emissions (tpy)			
			CO_2	CH_4	N_2O	Total GHG (CO_2e)
PDH MSS	Fractionation Section	2,278,000	388.8	1.2	6.5E-04	413.4
	Reactor Section	137,500	23.5	0.1	3.9E-05	25.0
TOTAL		2,415,500	**412.3**	**1.2**	**6.9E-04**	**438.3**

Process Gas Vented to Flare During Shutdown

Component	Weight Percent (%)	MW (kg/kgmol)	Carbon Atoms/mole	Carbon Content
Propane	66.70%	44.10	3	0.817
Propylene	33.30%	42.08	3	0.856
Total		43.43		0.830

Conversions & Emission Factors

8760	hr/yr
2000	lb/ton
0.0001	kg/MMBTU N_2O, from 40 CFR 98 Subpart C, Table C-2
0.001	kg/MMBTU CH_4, from 40 CFR 98 Subpart C, Table C-2
310	GWP for N_2O
21	GWP for CH_4
1	GWP for CO_2
0.001	conversion factor from kilograms to metric tons
1.1023	short tons/metric ton

Greenhouse Gas Emission Calculations - Process Fugitive Emissions Summary

Stream	GHG Fugitives (tpy)		
	Carbon Dioxide	Methane	TOTAL GHG (CO_2e)
Net Gas on CCR		1.04E-02	0.22
Net Gas - 369		5.19E-02	1.09
Tail Gas - 234		1.12E-02	0.23
Deethanizer Rectifier Reflux		1.69E-03	0.04
Deethanizer Stripped Overheads		1.17E-04	0.00
Deethanizer Rectifier Bottoms		1.04E-04	0.00
Deethanizer Feed		3.52E-04	0.01
Reactor 4 Effluent - 186		1.43E-02	0.30
Reactor 3 Effluent - 179		5.36E-04	0.01
Reactor 2 Effluent - 172		4.66E-04	0.01
Reactor 1 Effluent - 165		3.72E-04	0.01
Reactor 1 Influent - 162		5.11E-04	0.01
Natural Gas	1.58E-03	5.27E-02	1.11
Demethanizer		1.36E-03	0.03
TOTAL	**1.58E-03**	**1.46E-01**	**3.07**

[1]CO_2e = Total * Global Warming Potential (GWP)

GWP for CO_2 1

GWP for N_2O 310

GWP for CH_4 21

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:	Net gas on CCR	
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	14		0.0089	8760	0.526257	0.97	0.0158
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	47		0.0029	8760	0.590643	0.97	0.0177
Flanges/Connectors	Light Liquid				8760	0		0.0000
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor				8760	0		0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0335**

Stream Composition	Wt Fraction[1]	Total Speciated Emissions tons/yr
Hydrogen	0.63	2.11E-02
Methane	0.31	1.04E-02
Ethylene	0.00	9.94E-05
Ethane	0.03	8.45E-04
Propylene	0.02	5.17E-04
Propane	0.02	5.34E-04
		0.00E+00
		0.00E+00
		0.00E+00
Total Emissions		**3.35E-02**

Notes:
Net gas on CCR
Same composition

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:	369	
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	77		0.0089	8760	2.982123	0.97	0.0895
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	171		0.0029	8760	2.172042	0.97	0.0652
Flanges/Connectors	Light Liquid				8760	0		0.0000
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors		2		0.5027	8760	3.302739	1.00	0.0000
Relief Valve	Gas/Vapor	9		0.2293	8760	9.039006	1.00	0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections		3		0.033	8760	0.43362	0.97	0.0130
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.1676**

Stream Composition	Wt Fraction[1]	Total Speciated Emissions tons/yr
Hydrogen	0.63	1.06E-01
Methane	0.31	5.19E-02
Ethylene	0.00	4.97E-04
Ethane	0.03	4.23E-03
Propylene	0.02	2.59E-03
Propane	0.02	2.67E-03
		0.00E+00
		0.00E+00
		0.00E+00
Total Emissions		**1.68E-01**

Notes:
Net gas

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:		234
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	6		0.0089	8760	0.233892	0.97	0.0070
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	21		0.0029	8760	0.266742	0.97	0.0080
Flanges/Connectors	Light Liquid				8760	0		0.0000
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor				8760	0		0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections		2		0.033	8760	0.21681	0.97	0.0065
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0215**

Stream Composition	Wt Fraction[1]	Total Speciated Emissions tons/yr
Hydrogen	0.42	9.13E-03
Methane	0.52	1.12E-02
Ethylene	0.00	1.04E-04
Ethane	0.04	8.06E-04
Propylene	0.01	1.80E-04
Propane	0.01	1.23E-04
		0.00E+00
		0.00E+00
		0.00E+00
Total Emissions		**2.15E-02**

Notes:
Tail gas

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:		Deethanizer rectifier reflux
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	5		0.0089	8760	0.175419	0.97	0.0053
Valves	Light Liquid	38		0.0035	8760	0.574875	0.97	0.0172
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid	3		0.0386	8760	0.507204	1.00	0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	21		0.0029	8760	0.266742	0.97	0.0080
Flanges/Connectors	Light Liquid	99		0.0005	8760	0.21681	0.97	0.0065
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor	2		0.2293	8760	1.506501	1.00	0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections		2		0.033	8760	0.21681	0.97	0.0065
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0435**

Stream Composition	**Wt Fraction[1]**	**Total Speciated Emissions tons/yr**
Hydrogen	0.00	4.18E-06
Methane	0.04	1.69E-03
Ethylene	0.03	1.27E-03
Ethane	0.92	4.02E-02
Propylene	0.01	3.43E-04
Propane	0.00	5.71E-05
		0.00E+00
		0.00E+00
		0.00E+00
Total Emissions		**4.35E-02**

Notes:

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:		Deethanizer stripper overheads
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	5		0.0089	8760	0.175419	0.97	0.0053
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	21		0.0029	8760	0.266742	0.97	0.0080
Flanges/Connectors	Light Liquid	8		0.0005	8760	0.016425	0.97	0.0005
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor	2		0.2293	8760	1.506501	1.00	0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0138**

Stream Composition	**Wt Fraction[1]**	**Total Speciated Emissions tons/yr**
Hydrogen	5.40E-05	7.43E-07
Methane	0.01	1.17E-04
Ethylene	0.00	6.83E-05
Ethane	0.16	2.18E-03
Propylene	0.41	5.63E-03
Propane	0.42	5.76E-03
		0.00E+00
		0.00E+00
		0.00E+00
Total Emissions		**1.38E-02**

Notes:

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:		Deethanizer rectifier bottoms
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor				8760	0		0.0000
Valves	Light Liquid	17		0.0035	8760	0.252945	0.97	0.0076
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid	3		0.0386	8760	0.507204	1.00	0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor				8760	0		0.0000
Flanges/Connectors	Light Liquid	72		0.0005	8760	0.15768	0.97	0.0047
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor				8760	0		0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections		2		0.033	8760	0.21681	0.97	0.0065
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0188**

Stream Composition	Wt Fraction[1]	Total Speciated Emissions tons/yr
Hydrogen	0.00	4.24E-07
Methane	0.01	1.04E-04
Ethylene	0.00	7.98E-05
Ethane	0.14	2.70E-03
Propylene	0.42	7.88E-03
Propane	0.43	8.06E-03
		0.00E+00
		0.00E+00
		0.00E+00
Total Emissions		**1.88E-02**

Notes:

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:	Deethanizer feed	
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	2		0.0089	8760	0.058473	0.97	0.0018
Valves	Light Liquid	62		0.0035	8760	0.942795	0.97	0.0283
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid	3		0.0386	8760	0.507204	1.00	0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	12		0.0029	8760	0.152424	0.97	0.0046
Flanges/Connectors	Light Liquid	236		0.0005	8760	0.515745	0.97	0.0155
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors		3		0.5027	8760	6.605478	1.00	0.0000
Relief Valve	Gas/Vapor	3		0.2293	8760	3.013002	1.00	0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections		6		0.033	8760	0.86724	0.97	0.0260
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0761**

Stream Composition	Wt Fraction[1]	Total Speciated Emissions tons/yr
Methane	4.62E-03	3.52E-04
Hydrogen	1.79E-05	1.36E-06
Ethylene	1.23E-03	9.35E-05
Ethane	2.66E-02	2.03E-03
Propadiene	4.18E-05	3.18E-06
Methylacetylene	1.88E-04	1.43E-05
Propylene	3.00E-01	2.29E-02
Propane	6.64E-01	5.05E-02
Isobutene	6.44E-04	4.90E-05
Isobutane	1.36E-03	1.04E-04
Benzene	8.96E-04	6.82E-05
Total Emissions		**7.61E-02**

Notes:

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:		186
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	299		0.0089	8760	11.636127	0.97	0.3491
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	645		0.0029	8760	8.19279	0.97	0.2458
Flanges/Connectors	Light Liquid				8760	0		0.0000
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors		2		0.5027	8760	3.302739	1.00	0.0000
Relief Valve	Gas/Vapor	11		0.2293	8760	10.545507	1.00	0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections		2		0.033	8760	0.21681	0.97	0.0065
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.6014**

Stream Composition	Wt Fraction[1]	Total Speciated Emissions tons/yr
Hydrogen	0.04	2.28E-02
Methane	0.02	1.43E-02
Ethylene	0.00	8.03E-04
Ethane	0.03	1.59E-02
Propadiene	0.00	2.48E-05
Methylacetylene	0.00	1.04E-04
Propylene	0.28	1.70E-01
Propane	0.63	3.76E-01
1,3-Butadiene	0.00	1.60E-06
1-Butene	0.00	8.28E-06
cis-2-Butene	0.00	6.63E-06
trans-2-Butene	0.00	9.94E-06
Isobutene	0.00	3.74E-04
n-Butane	0.00	1.72E-06
Isobutane	0.00	7.72E-04
2-Methyl-1-Butene	0.00	2.07E-06
Isopentane	0.00	2.13E-06
Total Emissions		**6.01E-01**

Notes:
Reaction Section after 4th reactor to separation system

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:		179
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	11		0.0089	8760	0.409311	0.97	0.0123
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	33		0.0029	8760	0.419166	0.97	0.0126
Flanges/Connectors	Light Liquid				8760	0		0.0000
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor				8760	0		0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0249**

Stream Composition	Wt Fraction[1]	Total Speciated Emissions tons/yr
Hydrogen	0.03	8.52E-04
Methane	0.02	5.36E-04
Ethylene	0.00	2.10E-05
Ethane	0.02	5.80E-04
Propadiene	0.00	5.87E-07
Methylacetylene	0.00	2.49E-06
Propylene	0.23	5.69E-03
Propane	0.69	1.71E-02
1,3-Butadiene	0.00	6.60E-08
1-Butene	0.00	2.74E-07
cis-2-Butene	0.00	2.06E-07
trans-2-Butene	0.00	3.43E-07
Isobutene	0.00	1.39E-05
n-Butane	0.00	2.13E-07
Isobutane	0.00	3.38E-05
2-Methyl-1-Butene	0.00	8.56E-08
Isopentane	0.00	8.81E-08
Total Emissions		**2.49E-02**

Notes:
Reaction Section between the 3rd and 4th reactor

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description: 172		
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	11		0.0089	8760	0.409311	0.97	0.0123
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	33		0.0029	8760	0.419166	0.97	0.0126
Flanges/Connectors	Light Liquid				8760	0		0.0000
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor				8760	0		0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0249**

Stream Composition	Wt Fraction[1]	Total Speciated Emissions tons/yr
Hydrogen	0.03	7.60E-04
Methane	0.02	4.66E-04
Ethylene	0.00	1.15E-05
Ethane	0.02	4.70E-04
Propadiene	0.00	2.94E-07
Methylacetylene	0.00	1.32E-06
Propylene	0.17	4.23E-03
Propane	0.76	1.89E-02
1-Butene	0.00	2.74E-07
cis-2-Butene	0.00	2.06E-07
trans-2-Butene	0.00	2.74E-07
Isobutene	0.00	1.16E-05
n-Butane	0.00	4.26E-07
Isobutane	0.00	3.66E-05
2-Methyl-1-Butene	0.00	8.58E-08
Isopentane	0.00	8.82E-08
Total Emissions		**2.49E-02**

Notes:
Reaction Section between the 2nd and 3rd reactor

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:	165	
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	11		0.0089	8760	0.409311	0.97	0.0123
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	33		0.0029	8760	0.419166	0.97	0.0126
Flanges/Connectors	Light Liquid				8760	0		0.0000
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor				8760	0		0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0249**

Stream Composition	**Wt Fraction[1]**	**Total Speciated Emissions tons/yr**
Water	0.00	8.49E-12
Hydrogen	0.03	6.70E-04
Methane	0.01	3.72E-04
Ethylene	0.00	3.40E-06
Ethane	0.01	3.10E-04
Propadiene	0.00	9.80E-08
Methylacetylene	0.00	3.92E-07
Propylene	0.10	2.42E-03
Propane	0.85	2.10E-02
1-Butene	0.00	2.06E-07
cis-2-Butene	0.00	1.37E-07
trans-2-Butene	0.00	2.06E-07
Isobutene	0.00	7.83E-06
n-Butane	0.00	7.11E-07
Isobutane	0.00	4.09E-05
Total Emissions		**2.49E-02**

Notes:
Reaction Section between the 1st and 2nd reactor

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:	162	
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	18		0.0089	8760	0.701676	0.97	0.0211
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	65		0.0029	8760	0.819279	0.97	0.0246
Flanges/Connectors	Light Liquid				8760	0		0.0000
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor				8760	0		0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0456**

Stream Composition	**Wt Fraction[1]**	**Total Speciated Emissions tons/yr**
Water	0.00	1.56E-11
Hydrogen	0.02	1.04E-03
Methane	0.01	5.11E-04
Ethylene	0.00	4.79E-06
Ethane	0.01	2.51E-04
Propadiene	0.00	3.98E-08
Methylacetylene	0.00	9.00E-08
Propylene	0.01	3.37E-04
Propane	0.95	4.34E-02
1,3-Butadiene	0.00	4.59E-09
1-Butene	0.00	1.26E-07
Isobutene	0.00	3.78E-06
n-Butane	0.00	1.83E-06
Isobutane	0.00	8.76E-05
Total Emissions		**4.56E-02**

Notes:
Reaction Section before the 1st reactor

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:		Natural Gas
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	30		0.0089	8760	1.16946	0.97	0.0351
Valves	Light Liquid				8760	0		0.0000
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid				8760	0		0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	100		0.0029	8760	1.2702	0.97	0.0381
Flanges/Connectors	Light Liquid				8760	0		0.0000
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor	2		0.2293	8760	2.008668	1.00	0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.0732**

Stream Composition	**Wt Fraction[1]**	**Total Speciated Emissions tons/yr**
Methane	0.7198	5.27E-02
Ethane	0.0270	1.98E-03
Propane	0.0064	4.68E-04
Isobutane	0.0014	1.02E-04
n-Butane	0.0014	1.02E-04
i-Pentane	0.1408	1.03E-02
n-Pentane	0.0704	5.15E-03
n-Hexane		0.00E+00
Carbon Dioxide	0.0216	1.58E-03
Nitrogen	0.0113	8.27E-04
t-Butyl Mercaptan		0.00E+00
Methyl Ethyl Sulfide		0.00E+00
Hydrogen Sulfide		0.00E+00
Total Emissions		**7.32E-02**

Notes:

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Equipment Leak Fugitive Emissions

Quantified using TCEQ SOCMI without Ethylene Factors

Unit		Stream ID:				Stream Description:		Demethanizer
Equipment	**Service**	**Total # of Components**	**Regularly Scheduled AOV inspection (Y/N)**	**TCEQ Emission Factor (lbs/hr)**	**Hours of Operation**	**Total Emissions (tons/yr) Uncontrolled TOC**	**Reduction**	**Total Emissions (tons/yr)**
Valves	Gas/Vapor	25		0.0089	8760	0.97455	0.97	0.0292
Valves	Light Liquid	125		0.0035	8760	1.91625	0.97	0.0575
Valves	Heavy Liquid				8760	0		0.0000
Pumps	Light Liquid	7		0.0386	8760	1.183476	1.00	0.0000
Pumps	Heavy Liquid				8760	0		0.0000
Flanges/Connectors	Gas/Vapor	75		0.0029	8760	0.95265	0.97	0.0286
Flanges/Connectors	Light Liquid	350		0.0005	8760	0.7665	0.97	0.0230
Flanges/Connectors	Heavy Liquid				8760	0		0.0000
Compressors					8760	0		0.0000
Relief Valve	Gas/Vapor	15		0.2293	8760	15.06501	1.00	0.0000
Open-Ended Lines					8760	0		0.0000
Sampling Connections		5		0.033	8760	0.7227	0.97	0.0217
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
					8760	0		0.0000
						Total Emissions		**0.1600**

Stream Composition	**Wt Fraction[1]**	**Total Speciated Emissions tons/yr**
Hydrogen	5.40E-05	8.64E-06
Methane	0.01	1.36E-03
Ethylene	4.96E-03	7.94E-04
Ethane	0.16	2.53E-02
Propylene	0.41	6.55E-02
Propane	0.42	6.70E-02
		0.00E+00
		0.00E+00
		0.00E+00
Total Emissions		**1.60E-01**

Notes:

[1] Speciation of fugitive emissions are based on process simulation. Actual concentrations may vary.

Appendix B
PSD Netting Tables

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: TBD	Application Submittal Date: 2/11/2013
Company: C3 Petrochemicals LLC	
RN: RN106592579	Facility Location: Chocolate Bayou Complex
City: Alvin	County: Brazoria
Permit Unit I.D.: PDH Plant	Permit Name: PDH Plant
Permit Activity: ☒ New Source ☐ Modification	

Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**							
	Ozone							GHG
	VOC	**NO_x**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**SO_2**	(CO2e)
Nonattainment?								No
PSD?								Yes
Existing site PTE (tpy)?								>100,000
Proposed project emission increases (tpy from 2F[2])?								795,881
Is the existing site a major source?			Yes	Yes	Yes	Yes	Yes	Yes
If not, is the project a major source by itself?								
If site is major source, is project increase significant?								Yes
If netting required, estimated start of construction: January 2014								
5 years prior to start of construction January 2009								contemporaneous
Estimated start of operation 4th Quarter 2015								period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)								
Major NSR Applicable?								Yes

	VP - Env, Safety, Security, and Health	2/7/2013 (revised 7/2013)
Signature	***Title***	***Date***

[1] Other pollutants. [Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, etc.]

[2] Sum of proposed emissions minus baseline emissions, increases only.

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

TCEQ - 10154 (Revised 04/12) Table 1F
These forms are for use by facilities subject to air quality permit requirements and may be revised periodically. (APDG 5912v2)

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]: Greenhouse Gases (CO2e)	Permit: TBD
Baseline Period: NA - New facility to	

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1.	PDH BOILERS	PDH BOILERS			0.0	330,037				330,037
2.	Reaction Train 1	Various			0.0	230,296				230,296
3.	Reaction Train 2	Various			0.0	230,296				230,296
4	CCR Vents	CCR-1 and CCR-2			0.0	4,636				4,636
5.	PDH FUG	PDH FUG			0.0	3.1				3.1
6.	PDH FLARE	PDH FLARE			0.0	175.1				175.1
7.	PDH MSS	PDH MSS			0.0	438.3				438.3
8.										
9.										
								Page Subtotal[9]		795,881

[1] Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant
[2] Emission Point Number as designated in NSR Permit or Emissions Inventory
[3] All records and calculations for these values must be available upon request
[4] Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement
[5] If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement
[6] Proposed Emissions (column B) minus Baseline Emissions (column A)
[7] Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement
[8] Obtained by subtracting the correction from the difference. Must be a positive number.
[9] Sum all values for this page.

Appendix C

CCS Detailed BACT Analysis and Supplemental Information

Best Available Control Technology for Carbon Capture and Sequestration

In the EPA guidance document entitled *PSD and Title V Permitting Guidance for Greenhouse Gases*, dated March 2011, EPA recommends the use of the Agency's five-step "top-down" process to determine BACT for greenhouse gases (GHGs). This top-down process calls for the identification of all available control technologies for a given pollutant and the ranking of these technologies in descending order of control effectiveness. The applicant must then evaluate the highest-ranked option and the top-ranked option(s) should be established as BACT unless it is demonstrated that the technical considerations, or energy, environmental, or economic impacts and other costs justify a conclusion that the top-ranked technology is not achievable. If the most effective control strategy is eliminated, then the next most effective control should be evaluated until an option is selected as BACT. BACT cannot be less stringent than any applicable standard of performance under New Source Performance Standards (NSPS); however EPA has not promulgated any NSPS that contain emissions limits for GHGs.

EPA has divided the process of determining BACT into five steps:

- Step 1: Identify all available control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies
- Step 4: Evaluate economic, energy and environmental impacts
- Step 5: Select the BACT

This five-step process is generally performed for each individual GHG emission source. As discussed in Section 6 of this permit application, Carbon Capture and Sequestration (CCS) is a potential control technology for several relatively large sources of GHG emissions from the C3P PDH plant. These are process heaters, boilers, and the continuous catalyst regeneration (CCR) vents. It is not considered technically feasible to capture GHG emissions emitted by the process flare or to collect CO_2 emissions from leaking fugitive emission components. Therefore, the process flare and fugitive emissions have not been included in this evaluation of the feasibility of CCS.

Five-Step BACT Evaluation of CCS

Step 1: Identify All Available Control Technologies

In the guidance document *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA classifies CCS as an add-on pollution control technology available for large CO_2-emitting facilities. CCS is identified in Section 6 of the application as one of the alternatives for controlling GHG emissions from gas-fired sources (process heaters and boilers) and the CCR vents.

The emerging CCS technologies consist of processes for separation of CO_2 from combustion or process gases (i.e. capture), compression and transportation of this CO_2 (typically via pipeline), and then injection into suitable geologic formations (i.e. sequestration). These geologic formations include oil and gas reservoirs, unmineable coal seams, and underground saline formations.

Of the emerging CO_2 capture technologies, amine absorption is the only commercially available technology for the CO_2 separation process. Amine absorption has been utilized by processes in the petroleum refining and natural gas processing industries and for exhausts from gas-fired industrial boilers. The amine solvent used in these absorption units has been demonstrated to remove approximately 90% of the CO_2 from power plant exhaust streams, but is considered to be highly energy-intensive.[10] The GHG sources in the PDH plant will all contain CO_2 in high volume, dilute concentration streams at low pressure. This will require that a large amount of energy be generated and consumed for the volume of gas treated to capture the CO_2. In addition, impurities in the GHG vent streams such as particulate matter, sulfur dioxide, and nitrogen oxides may degrade the amine sorbents and result in the reduced effectiveness of the CO_2 capture process.[11]

In order to be transported, the captured CO_2 must first be compressed. Compressor stations require large amounts of power, representing a significant cost and environmental impact due to the energy required to compress the gas. It is estimated that 70-90 percent of the cost per tonne of CO_2 is associated with capture and compression of the gas.[12] Transportation of CO_2 is typically done via pipeline. According to the *Report of the Interagency Task Force on Carbon Capture and Storage*, there are currently approximately 3,600 miles of existing CO_2 pipeline. Additional compression and pipeline infrastructure would be necessary for this project.

If CO_2 capture and compression can be achieved, it must then be routed to a suitable geologic formation for long-term storage. This geologic storage involves the injection of supercritical CO_2 into deep geologic formations under sealing zones or geologic traps that will prevent the CO_2

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10 DOE-NETL, *Carbon Sequestration: FAQ Information Portal,* http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (visited February 1, 2013)

11 Ibid

12 Report of the Interagency Task Force on Carbon Capture and Storage (http://www.epa.gov/climatechange/Downloads/ccs/ES-CCS-Task-Force-Report-2010.pdf)

from escaping.[13] Some of the challenges associated with geological storage are the availability of storage capacity and the possible adverse impacts associated with the long-term storage of CO_2 (e.g. unanticipated migration and leakage of CO_2 and changes in subsurface pressures that could impact drinking water, human health and ecosystems).[14]

Step 2: Eliminate Technically Infeasible Options

According to the guidance documents for GHG permitting and for reducing CO_2 emissions, EPA has concluded that although CCS technologies exist, it does not necessarily mean CCS would be selected as BACT due to its technical and economic infeasibility. In addition, EPA supports the conclusion of the Interagency Task Force on Carbon Capture that current technologies could be used to capture CO_2 from new and existing plants, but are not ready for widespread implementation.[15] This is primarily because they have not been demonstrated at the scale necessary to establish confidence in their operations for high volume commercial deployment.

The goal of CO_2 capture is to concentrate the CO_2 stream from an emitting source for transport and injection at a storage site. CCS requires a highly concentrated, pure CO_2 stream for practical and economic reasons. The primary sources of CO_2 associated with this PDH project are exhaust gas from combustion devices and process vents from the CCR section of the plant. The exhaust gas streams from all of these sources have characteristics that make it technically difficult to employ CCS. These characteristics include:

- Multiple contaminants – PM, SO_2, NO_X and other products of combustion from boilers and heaters
- Low pressure – atmospheric
- High temperature – 450^o F for boilers and heaters, 300^o F for CCR vents
- High volume – 16.3 MMscf/hr for boilers, 9.4 MMscf/hr for heaters, 1.6 MMscf/day for CCR vents
- Low CO_2 concentrations – approximately 10%

The exhaust gases from combustion sources and process vents would require the installation and operation of additional equipment to capture, separate, cool, and pressurize the CO_2 for transportation. In addition, it would require compression to increase the pressure from atmospheric to a pressure required for efficient CO_2 separation. After separated, additional compression would be required to pressurize the CO_2 to that of the pipeline (estimated to be

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[13] DOE-NETL, *Carbon Sequestration: Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (visited February 1, 2013)

[14] "Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide" (EPA, July 2008)

[15] PSD and Title V Permitting Guidance for Greenhouses Gases (EPA, March 2011)

~2000 psia). In practice, a series of compressors would be needed, which would increase the overall capital and operational cost. A cooling mechanism (e.g. complex heat exchangers) would also be required to reduce the temperature of the streams from 450^o F for boilers and heaters and from 300^{o}F for the CCR vents to less than 100°F prior to separation. To achieve separation, an amine unit or an equivalent would be required to capture the CO_2, therefore the equipment (including final compression) must be designed to handle acidic gases, which would result in additional cost. The entire system would require both high energy consumption and cost to compress, separate, and cool the exhaust gas for processing and transport requirements. The combination of all the additional equipment and operations described above would have an additional adverse impact on the environment.

Assuming that the CO_2 capture and compression is feasible, the CO_2 stream would need to be transported to a facility capable of long-term sequestration and storage. A pipeline would be required to transport the gas to the closest geologic formation capable of storing the CO_2. The closest site that is currently being field-tested to demonstrate its capacity for large-scale, long-term storage of CO_2 is the Southeast Regional Carbon Sequestration Partnership's (SECARB) Cranfield test site in Mississippi. This test site is over 320 miles away and would require a lengthy and sizable pipeline and numerous compression and recompression facilities if the CO_2 generated by the PDH plant were to be transported to Cranfield. The distance between the C3P PDH plant and Cranfield makes the transportation infeasible.

As an alternative it is possible that the CO_2 could be transported to the nearest pipeline planned by Denbury Green Pipeline – Texas. This pipeline is intended to provide CO_2 to support various enhanced oil recovery (EOR) operations in Southeast Texas. Construction of the Denbury pipeline is scheduled to begin in late 2013. Numerous logistical hurdles would be presented by this option that include construction of an inter-connecting pipeline, offsite land acquisition and easements, governmental regulatory approvals, and the timing of available transportation infrastructure. For the purposes of this evaluation, it is assumed that the Denbury pipeline would be used. However, it should be noted that none of the Southeast Texas EOR reservoirs or other local geologic formations have been demonstrated as viable options for large-scale, long-term storage of CO_2 and that there are no guarantees that the projected end users will use this CO_2 stream on a perpetual or long-term basis with sufficient demand.

In the Statement of Basis for GHG permits recently issued by EPA Region 6, EPA concludes that "while there are some portions of CCS that are technically infeasible, EPA has determined that overall CCS technologies are technologically feasible" at the permitted sources. Each CCS component, technology and the technical feasibility (or infeasibility) is noted. A summary of these components, technologies and their technical feasibility is summarized in the following table.

Step Two Summary for CCS from EPA Region 6

CCS Component	CCS Technology	Technical Feasibility
Capture	Post-combustion	Y
	Pre-combustion	N
	Oxyfuel combustion	N
	Industrial separation (natural gas processing, ammonia production)	N
Transportation	Pipeline	Y
	Shipping	Y
Geological Storage	Enhanced Oil Recovery	Y
	Gas or oil fields	N*
	Saline formations	N*
	Enhanced Coal Bed Methane Recovery (ECBM)	N*
Ocean Storage	Direct injection (dissolution type)	N*
	Direct injection (lake type)	N*
Mineral carbonation	Natural silicate minerals	N*
	Waste minerals	N*
Large scale CO_2 Utilization/Application		N*

*Both geologic storage and large scale CO_2 utilization technologies are in the research and development phase and currently commercially unavailable

As indicated in EPA's *PSD Permitting Guidance for Greenhouse Gases*, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture and storage of GHGs are determined to be generally available from commercial vendors. Based on the information provided in this step, C3P believes that the application of CCS for the heaters, boilers, and CCR vents has not been demonstrated on similar sources and should be eliminated from any further consideration as a potential control technology for GHGs. It is clear that there are significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review. The remainder of this evaluation will delineate the other reasons CCS is not considered to be a viable control technology for these emission sources.

Step 3: Rank Remaining Control Technologies

As documented in Step 2, implementation of CCS technology for the C3P PDH plant is not considered commercially available or technically feasible. The economic feasibility of CCS will be discussed in detail in Step 4.

Step 4: Evaluate Economic, Energy and Environmental Impacts

EPA considers CCS to be an available control option for high-purity CO_2 streams that merits initial consideration as part of the BACT review process, especially for new facilities. As noted in EPA's GHG Permitting Guidance, a control technology is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of clean coal technology. As part of its work, the Task Force prepared a report that summarized the state of CCS and identified technical and non-technical challenges to implementation. EPA, which participated in the Interagency Task Force, supported the Task Force's conclusion that although current technologies could be used to capture CO_2 from new and existing plants, they were not ready for widespread implementation at all types of facilities. This conclusion was based primarily on the fact that the technologies had not been demonstrated on the scale necessary to establish confidence in their operations. Nothing has changed significantly in the industry since the August 2010 report, and there is no specific evidence supporting the feasibility and cost-effectiveness of a full scale carbon capture system for the project and emission sources proposed by C3P.

In addition to the information provided in Step 2 of this evaluation, C3P has also considered a number of other environmental and operational issues related to the operation of CCS. Operation of capture and compression units will require a substantial amount of additional electricity. For example, it has been reported that operation of carbon capture equipment at a typical natural gas fired combined cycle plant will reduce net efficiency of the plant from approximately 50% to approximately 42.7% (based on fuel higher heating value).[16] A similar loss in efficiency is anticipated for boilers and heaters.

[16] US Department of Energy, National Energy Technology Laboratory, "Costs and Performance Baseline for Fossil Energy Plants, Volume 1 – Bituminous Coal and Natural Gas to Energy", Revision 2, November 2010

For the purpose of this BACT analysis, C3P has determined that the proposed Denbury pipeline is the nearest potentially available CO_2 pipeline (for EOR, rather than CCS). It will be approximately 14 miles from the PDH plant location and is scheduled to begin construction in late 2013. The construction of a pipeline from C3P to the Denbury pipeline will require the purchase of right-of-ways, planning, environmental studies and possible mitigation of environmental impacts from pipeline construction.

In addition to the technical and operational challenges described above, CCS will also result in considerable costs. C3P has estimated these costs and summarized them in Table C-1. It should be noted that this cost estimate is conservatively low because it does not include all costs, such as piping for on-site gathering systems required to collect vent gas from various sources, additional electricity required to power the capture and compression systems, and cost of obtaining right-of-ways and permits for pipeline construction. It also assumes that the pipeline will only be 14 miles (22.45 km), which is the distance to the proposed Denbury pipeline. If the proposed Denbury pipeline is not constructed or if the projected EOR customers do not continuously accept this CO_2 stream, pipeline costs incurred to transport CO_2 to undetermined alternate locations will be higher.

The CCS cost estimate in Table C-1, does not include the potential costs associated with long-term liability potentially arising from geologic storage of CO_2 in formations supporting EOR, rather than permanent sequestration. Nevertheless, the average annual cost associated with CCS for the C3P PDH plant is approximately $80.9 MM. Even though considered to be conservatively low, this demonstrates that CCS is economically unreasonable. Therefore, CCS is not considered a technically, economically, or commercially viable control option for this project.

Step 5: Select BACT

As demonstrated in Steps 2 and 4 of this BACT review, CCS is not commercially available, is technically infeasible, and is economically unreasonable. Therefore it should not be considered BACT for the C3P PDH plant.

Table C-1

Southeast Texas EOR Alternative
Range of Approximate Annual Costs for Installation and Operation of Capture, Transport, and Storage Systems for Control of CO_2 Emissions

Carbon Capture and Storage (CCS) Component System	Factors for Approximate Costs for CCS Systems	Annual System CO_2 Throughput (tons of CO_2 captured, transported, and stored) [1]	Pipeline Length for CO_2 Transport System (km CO_2 transported) [4]	Range of Approximate Annual Costs for CCS Systems ($)
Post-Combustion CO_2 Capture and Compression System	$103.42 / ton of CO_2 avoided [2]	715,084		$73,954,008
CO_2 Transport System				
Minimum Cost	$0.91 / ton of CO_2 transported per 100 km [2]	715,084	22.45	$146,090
Maximum Cost	$2.72 / ton of CO_2 transported per 100 km [2]	715,084	22.45	$436,665
Average Cost	$1.82 / ton of CO_2 transported per 100 km [3]	715,084	22.45	$291,377
CO_2 Storage System				
Minimum Cost	$0.51 / ton of CO_2 stored [2,5]	715,084		$364,693
Maximum Cost	$18.14 / ton of CO_2 stored [2,5]	715,084		$12,971,627
Average Cost	$9.33 / ton of CO_2 stored [3,5]	715,084		$6,668,160
Total Cost for CO_2 Capture, Transport, and Storage Systems				
Minimum Cost	$104.13 / ton of CO_2 removed	715,084		$74,464,791
Maximum Cost	$122.17 / ton of CO_2 removed	715,084		$87,362,300
Average Cost	$113.15 / ton of CO_2 removed [3]	715,084		$80,913,546

Notes:

[1] Assumes the maximum annual CO_2 emission rates from heaters, boilers, and CCR vents and that a capture system operates with 90% efficiency

[2] These cost factors are from *Report of the Interagency Task Force on Carbon Capture and Storage* , pp. 33, 34, 37, and 44 (Aug 2010)(http://www.epa.gov/climatechange/policy/ccs_task_force.html). The factors from the report in the form of $/tonne of CO_2 avoided, transported, or stored and have been converted to $/ton. Per the report, the factors are based on the increased cost of electricity (COE; in $/kW-h) of an "energy-generating system, including all the costs overs its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital."

[3] The average cost factors were calculated as the arithmetic mean of the minimum and maximum factors for each CCS component system and for all systems combined.

[4] The length of the pipeline to tie into the Denbury System was provided by Pipeline Technology LLC.

[5] "Cost estimates [for geologic storage of CO_2] are limited to capital and operational costs, and do not include potential costs associated with long-term liability." (from the *Report of the Interagency Task Force on Carbon Capture and Storage* , p. 44)

Appendix D

RACT/BACT/LAER Clearinghouse (RBLC) Search Results

Table D-1: RBLC Summary for Greenhouse Gas Emissions from Process Heaters

Date	RBLC ID	Company	Facility	Permit Number	Process Name	Pollutant	Control Method	Emission Limit
6/8/2012	SC-0142	Showa Denko Carbon, Inc.	Graphite Electrode Manufacturing Facility	0900-00250CZ	Natural gas-fired hot oil heater (5 MMBtu/hr)	CO_2e	Good combustion practices, annual tune up, low NO_x burners	3093 tons/yr
					Natural gas-fired pitch impregnation preheater (12 MMBtu/hr)			7524 tons/yr
5/24/2012	TX-0627	Energy Transfer Partners, LP	Lone Star NGL, Mont Belvieu Gas Plant	PSD-TX-1264-GHG	Plant heater system (4 heaters per plant, 4 plants, range from 3 to 48.5 MMBtu/hr)	CO_2	Not specified	1102.5 lb CO_2/MMSCF, 365-day rolling average
10/18/2011	CA-1212	City of Palmdale	Palmdale Hybrid Power Project	SE 09-01	Natural gas-fired auxiliary heater (40 MMBtu/hr)	CO_2e	Annual boiler tune ups	Not specified

Table D-2: RBLC Summary for Greenhouse Gas Emissions from Boilers

Date	RBLC ID	Company	Facility	Permit Number	Process Name	Pollutant	Control Method	Emission Limit
5/1/2013	LA-0266	Crosstex Processing Services, LLC	Eunice Gas Extraction Plant	PSD-LA-569 (M-1)	Natural gas-fired boiler (359 MMBtu/hr)	CO_2e	Energy efficiency measures: improved combustion measures (e.g., combustion tuning, optimization using parametric testing, advanced digital instrumentation such as temperature sensors, oxygen monitors, CO monitors, and oxygen trim controls); use of an economizer; boiler insulation; and minimization of air infiltration.	87.6 tons/MM lb steam, 12-month rolling average
4/19/2013	VT-0039	North Springfield Sustainable Energy Project, LLC	North Springfield Sustainable Energy Project	AP-11-038	Wood fired boiler (464 MMBtu/hr)	CO_2e	Energy efficient design and the use of a thermal district heat loop	2668 lb/mw-hr, 12-month rolling average
3/1/2013	NE-0054	Cargill, Incorporated	Cargill, Incorporated	12-042	Natural gas-fired boiler (300 MMBtu/hr)	CO_2e	Good combustion practices	Not specified
10/26/2012	IA-0105	Iowa Fertilizer Company	Nitrogenous Fertilizer Manufacturing	12-219	Natural gas-fired auxiliary boiler (472.4 MMBtu/hr)	CO_2e	Good combustion practices	51,748 tons/yr, rolling 12-month total
						CO_2		117 lb/MMBtu, rolling 30-day average
						CH_4		0.0023 lb/MMBtu, avg. of 3 stack test runs
						N_2O		0.006 lb/MMBtu, avg. of 3 stack test runs
8/24/2012	TX-0629	BASF TOTAL Petrochemicals LP	BASF TOTAL Petrochemicals LP	PSD-TX-903-GHG	Natural gas and fuel gas-fired package boilers (425.4 MMBtu/hr)	CO_2	Selective catalytic reduction (SCR)	420,095 tons/yr, 12-month rolling average basis
8/20/2012	AK-0076	Exxon Mobil Corporation	Point Thomson Production Facility	AQ1201CPT01	Diesel-fired boiler (6 MMBtu/hr)	CO_2	Good combustion practices	Not specified
2/10/2012	VT-0037	Beaver Wood Energy Fair Haven, LLC	Beaver Wood Energy Fair Haven	AP-11-014	Wood fired boiler (482 MMBtu/hr)	CO_2e	Implement energy efficiency and good operating and maintenance practices	2,993 lb/MW gross electric output, 30-day rolling average
2/8/2012	SC-0113	Pyramax Ceramics, LLC	Pyramax Ceramics, LLC	0160-0023	Natural gas-fired boilers (5 MMBtu/hr each)	CO_2	Good design and combustion practices	Not specified

Table D-2: RBLC Summary for Greenhouse Gas Emissions from Boilers

Date	RBLC ID	Company	Facility	Permit Number	Process Name	Pollutant	Control Method	Emission Limit
1/27/2012	GA-0147	Pyramax Ceramics, LLC	Pyyramax Ceramics - King's M:U Facility	3295-163-0035-P-01-0	Natural gas-fired boiler (9.8 MMBtu/hr)	CO_2e	Good combustion practices, design, and thermal insulation	5,809 tons, 12-month rolling average
1/12/2012	IA-0101	Interstate Power and Light	Ottumwa Generating Station	78-A-019-P10	Coal-fired boiler (8669 MMBtu/hr	CO_2e	Good combustion practices	8,000,325 tons/yr, rolling 12-month total
						CO_2		2927.1 lb/MWH (Net), 30-day rolling average
12/1/2011	FL-0330	Port Dolphin Energy LLC	Port Dolphin Energy LLC	DPA-EPA-R4001	Natural gas-fired boilers (278 MMBtu/hr)	CO_2e	Tuning, optimization, instrumentation and controls, insulation, and turbulent flow	117 lb/MMBtu, 8-hour rolling average
10/27/2011	FL-0328	ENI U.S. Operating Company, Inc.	ENI - Holy Cross Drilling Project	OCS-EPA-R4007	Diesel-fired boiler (9.6 MMBtu/hr)	CO_2	Good combustion and maintenance practices based on manufacturer's specifications	565 tons/yr, 12-month rolling basis
10/18/2011	CA-1212	City of Palmdale	Palmdale Hybrid Power Project	SE 09-01	Natural gas-fired auxiliary boiler (110 MMBtu/hr)	CO_2e	Annual boiler tune ups	Not specified
8/16/2011	LA-0254	Entergy Louisiana LLC	Ninemile Point Electric Generating Plant	PSD-LA-752	Natural gas-fired auxiliary boiler (338 MMBtu/hr)	CO_2	Proper operation and good combustion practices	117 lb/MMBtu
						CH_4		0.0022 lb/MMBtu
						N_2O		0.0002 lb/MMBtu
6/29/2011	MI-0400	Wolverine Power Supply Cooperative, Inc.	Wolverine Power	317-07	Circulating fluidized bed petcoke/coal boilers (3030 MMBtu/hr each)	CO_2e	Use of biomass and energy efficiencies	2.1 lb/kwh and 6,024,107 tons/yr, 12-month rolling average
4/6/2010	CT-0156	NRG Energy	Montville Power LLC	107-0056	42 MW wood-fired biomass utility boiler (600 MMBtu/hr)	CO_2e	Incorporate energy efficiency measures into final design; estimate annual natural gas (CH4) losses from pipeline and components; estimate annual fugitive SF6 circuit breaker losses; and report actual heat rates, overall efficiency, CO2e emissions for all modes of operation after one year of operational data.	590,103 tons/yr and 15,564 Btu/kwh (gross), 12-month rolling average

Table D-3: RBLC Summary for Greenhouse Gas Emissions from Flares

Date	RBLC ID	Company	Facility	Permit Number	Process Name	Pollutant	Control Method	Control Efficiency
5/1/2013	LA-0266	Crosstex Processing Services, LLC	Eunice Gas Extraction Plant	PSD-LA-569 (M-1)	Smokeless Flare	CO_2e	Good combustion practices	Not specified
8/20/2012	AK-0076	Exxon Mobil Corporation	Point Thomson Production Facility	AQ1201CPT01	Flare	CO_2	Good combustion practices	Not specified
12/6/2011	LA-0257	Sabine Pass LNG, LP and Sabine Pass Liquefaction, LLC	Sabine Pass LNG Terminal	PSD-LA-703 (M3)	Marine Flare	CO_2e	Proper plant operations and maintain the presence of the flame when gas is routed to the flare	Not specified
					Wet/Dry Gas Flares (4)			
11/10/2011	IN-0135	Hoosier Energy Rec Inc.	Merom Generating Stations	153-29394-00005	Methane-fired standby flare with propane-fired pilot	CO_2	Good combustion practices and proper maintenance	3235 lb/MWH, 4852 tons/12 consecutive month period
						CH_4		0.06 lb/MWH, 0.08 tons/12 consecutive month period
						N_2O		0.05 lb/MWH, 0.08 tons/12 consecutive month period

Table D-4: RBLC Summary for Greenhouse Gas Emissions from Equipment Leak Fugitives

Date	RBLC ID	Company	Facility	Permit Number	Process Name	Pollutant	Control Approach	Control Efficiency
5/1/2013	LA-0266	Crosstex Processing Services, LLC	Eunice Gas Extraction Plant	PSD-LA-569 (M-1)	Process Fugitives	CO_2e	LDAR Programs: NSPS KKK and LAC 33:III.2121	Not specified
7/25/2012	LA-0263	Phillips 66 Company	Alliance Refinery	PSD-LA-760	Hydrogen Plant Fugitives	CO_2e	Implement Louisiana Refinery MACT LDAR Program; monitor for total hydrocarbon instead of VOC	Not specified
12/6/2011	LA-0257	Sabine Pass LNG, LP and Sabine Pass Liquefaction, LLC	Sabine Pass LNG Terminal	PSD-LA-703 (M3)	Fugitive Emissions	CO_2e	Conduct a LDAR Program	Not specified
12/1/2011	FL-0330	Port Dolphin Energy LLC	Port Dolphin Energy LLC	DPA-EPA-R4001	Process Piping Fugitives	CO_2	Gas and leak detection system will be used	Not specified
11/10/2011	TX-0612	Lower Colorado River Authority	Thomas C. Ferguson Power Plant	PSD-TX-1244-GHG	Fugitive Natural Gas Emissions	CO_2e	No Controls Feasible	Not specified
						CH_4		

Appendix E

EPA Region 6 Benchmarking

Table E-1: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Process Heaters

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	Description of Heater(s)	Thermal Efficiency (%)	Heat Input (MMBtu/hr)	GHG Emissions (pounds CO_2e/MMBtu)
C3 Petrochemicals	New Propane Dehydrogenation Plant	2/12/2013		Heaters for PDH reaction	87%	Heater 1: 126 Heater 2: 135 Heater 3: 96 Heater 4: 78	121
Alpha Olefins Chemical Company, LLC, Freeport, Texas	Alpha Olefins Plant	5/17/2013		Hot oil heaters (2)	87%	189.2	113
Copano, Houston Central Gas Plant	Cryogenic Process Unit	6/6/2012	PSD-TX-104949-GHG	Supplemental gas-fired heaters	Not specified	25	117
Diamond Shamrock Company, Valero McKee Refinery	Crude Oil Refinery	12/1/2011		Vacuum heater	Not specified	75.1	115
				Charge heater	Not specified	33.3	115
DCP Midstream, LP - Hardin County NGL Fractionation Plant	Natural Gas Liquids Fractionation Facility	5/25/2012		Hot oil heaters (9), natural-gas fired	Not specified	90	131
				Regeneration heaters (3), natural-gas fired	Not specified	14.7	131
DCP Midstream, LP - Jefferson County NGL Fractionation Plant	Natural Gas Liquids Fractionation Facility	7/10/2012		Hot oil heaters (2), natural-gas fired	85%	179	119
				Regeneration heaters (2), natural-gas fired	Not specified	36	119
Enterprise Products Operating, Mont Belvieu Complex Eagleford Fractionation and DIB Units	Natural Gas Liquids Fractionator and Deisobutanizer	5/2012	PSD-TX-1286-GHG	Hot oil heaters (2)	85%	140	119
				Regenerant heaters (2)	80%	28.5	119
Enterprise Products, Mont Belvieu Propane Dehydrogenation Plant	New Propane Dehydrogenation Plant	12/19/2012		Reactor charge heater	90%	487	132
				Regeneration air heater	Not specified	1,189	125
Enterprise Products, Fractionation Units IX and X	Oil and Gas Production	2/14/2013		Hot oil heaters (2)	89%	140	131
				Regeneration heaters (2)	80%	28.5	147

Table E-1: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Process Heaters

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	Description of Heater(s)	Thermal Efficiency (%)	Heat Input (MMBtu/hr)	GHG Emissions (pounds CO_2e/MMBtu)
Energy Transfer Company, Jackson County Plant	Natural Gas Processing Plant	3/15/2012	PSD-TX-1264-GHG	Hot oil heater	Not specified	48.5	117
				Trim heater	Not specified	17.4	117
				Mole sieve regeneration heater	Not specified	9.7	117
				TEG regeneration heater	Not specified	3	117
				Stabilization unit heater	Not specified	5.8	117
Energy Transfer Partners, LP, Mont Belvieu	Gas Processing Plant	12/7/2011	PSD-TX-93813-GHG	Hot oil heater	Not specified	270	117
				Mole sieve regeneration heater	Not specified	46	117
Equistar Chemical, Olefins Plant Expansion Project - Corpus Christi Complex	Olefins and Aromatics Expansion	3/6/2013		Steam super heaters (2)	Not specified	146	114
Exelon La Porte Mountain Creek Steam Electric Expansion Project	Steam Electric Generation Facility	11/30/2012		Dewpoint heater, natural gas-fired	Not specified	2	117
Flint Hills Resources Corpus Christi, LLC, West Refinery	Refinery Expansion	12/18/2012		CCR Hot oil heater	92%	123.6	130
				Sat Gas #3 Hot oil heater	92%	450	117
Formosa Plastics, Olefins Expansion	Olefins Expansion and PDH Plant	12/11/2012		PDH Reactors	Not specified	180	368
Freeport LNG Development, Liquefaction Plant	Natural Gas Liquefaction Plant	12/21/2011		8 LT Heaters, 2 HT Heaters	80%	85	117
Invenergy Thermal Development LLC	Simple Cycle Power Generation	6/26/2013		Natural gas-fired dew-point heater	68%	9	117
KM Liquids Terminals	New Condensate Splitter	3/27/2012	PSD-TX-101199-GHG	Natural gas-fired heaters	85%	247	107
Las Brisas Energy Center, LLC	Circulating Fluidized Bed Steam Electric Generation Facility	10/28/2011		Propane vaporizers	Not specified	16	136

Table E-1: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Process Heaters

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	Description of Heater(s)	Thermal Efficiency (%)	Heat Input (MMBtu/hr)	GHG Emissions (pounds CO_2e/MMBtu)
Lone Star NGL Fractionators LLC, Mont Belvieu Gas Plant	NGL Fractionation Plant	6/7/2013		Hot oil heater	90.2%	215	138
				Regeneration Heater	74.8%	59	138
M&G Resins USA, LLC	Plastic Resin Manufacturing Plant	3/4/2013		Natural gas and process gas-fired heaters	Not specified	128	117
Natgasoline, LLC	Natural Gas to Gasoline Plant	2/19/2013		Reaction Heaters (5)	Not specified	122	117
				Regeneration Heater	Not specified	23	115
				HGT Treater Heater	Not specified	7	114
OCI Beaumont LLC	Methanol Unit Primary Reformers	12/21/2012		Pre-reformer fired heater	Not specified	250	117
ONEOK Hydrocarbon	NGL Fractionation Plant	9/21/2012	PSD-TX-106921-GHG (draft)	Hot oil heaters (3)	91%	154	106
PL Propylene	Modification to PDH Plant	2/2012	PSD-TX-18999-GHG	Charge gas heater	Not specified	373	117
				Regeneration Air Heater	Not specified	200	117
Targa Gas Processing	Natural Gas Processing Plant	2/23/2012	PSD-TX-106793-GHG	TEG Reboiler	Not specified	2	117
				Regeneration Heater		12	117
				Hot Oil Heater		98	117
Targa Midstream Services	NGL Fractionation Plant	3/26/2012		Hot Oil Heaters	Not specified	144	117
Tenaska Brownsville Partners, LLC	Gas-Fired Turbine and HRSG	2/15/2013		Fuel Gas Heater	Not specified	10	117

Table E-2: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Boilers

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	Description of Boiler(s)	Thermal Efficiency %	Heat Input (MMBtu/hr)	GHG Emissions (pounds CO_2e/MMBtu)
C3P PDH Plant	New Propane Dehydrogenation Plant	2/12/2013		2 Natural gas-fired boilers	82.0%	415	91
Air Liquide Large Industries U.S., LP – Bayou Cogen Plant	Cogeneration Plant	9/18/2012		3 Natural gas-fired boilers	Not specified	550	87
BASF FINA Petrochemicals LP	Ethylene Cracker	5/17/2011	PSD-TX-903-GHG	2 Natural or fuel-gas fired boilers	77%	425.4	113
Chevron Phillips Chemical Co.	Ethylene Unit	12/19/2011	PSD-TX-748-GHG	Natural or plant fuel gas-fired	77%	500	160
Diamond Shamrock Company, Valero McKee Refinery	Crude Oil Refinery	12/1/2011		1 boiler, burns refinery fuel gas	Not specified	225	115
Enterprise Products, Mont Belvieu Propane Dehydrogenation Plant	Propane Dehydrogenation Plant	12/19/2012		Waste heat boiler	Not specified	34	132
				Auxiliary boilers (2)	Not provided	248,500	132
ExxonMobil Chemical, Mont Belvieu Plastics Plant	Polyethylene Plant	5/22/2012		Natural gas-fired boilers (2)	77%	98	119
Formosa Plastics, Olefins Expansion	Olefins Expansion and PDH Plant	12/11/2012		4 Fuel gas-fired steam boilers combined with natural gas supplement	78%	431	117
INVISTA, S.a.r.l.	Modernization of Existing Boilers	3/13/2012	PSD-TX-812-GHG	4 Natural gas-fired and gaseous and liquid fuels-fired from the process	75-78%	Not specified	Not specified
La Paloma Energy Center	Combined Cycle Electric Generating Plant	7/2012	PSD-TX-1288-GHG (draft)	1 Natural gas-fired auxiliary boiler	80%	150	117
Las Brisas Energy Center, LLC	Circulating Fluidized Bed Steam Electric Generation Facility	10/28/2011		CFB Boilers (pet coke fueled)	Not specified	3080	241
				Natural gas-fired auxiliary boilers	Not specified	180	117
Natgasoline, LLC	Natural Gas to Gasoline Plant	2/19/2013		Auxiliary Boiler	85%	664	117
NRG Texas Power LLC, SR Bertron	Combined Cycle Electric Generating Unit	11/26/2012		1 Natural gas-fired auxiliary boiler	Not specified	80	117
NRG Texas Power LLC, Cedar Bayou Unit 5	Combined Cycle Electric Generating Unit	11/26/2012		1 Natural gas-fired auxiliary boiler	Not specified	80	117

Table E-2: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Boilers

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	Description of Boiler(s)	Thermal Efficiency %	Heat Input (MMBtu/hr)	GHG Emissions (pounds CO_2e/MMBtu)
NRG Development Company, Corpus Christi	Combined Heat and Power Plant	3/27/2013		Natural gas-fired auxiliary boiler	Not specified	483	117
				Natural gas-fired auxiliary boiler	Not specified	63	117
Pinecrest Energy Center, LLC	Combined Cycle Electric Generating Unit	2/28/2013		1 Natural gas-fired auxiliary boiler	80%	150	117
PL Propylene	Propane Dehydrogenation Plant	2/2012	PSD-TX-18999-GHG	Natural gas and process fuel gas supplemented waste heat boiler	Not specified	383	117
Rohm and Haas Deer Park	Chemical Manufacturing Facility	10/26/2012		2 Natural gas and process gas-fired boilers	76%	515	120
Tenaska Brownsville Partners, LLC	Gas-Fired Turbine and HRSG	2/15/2013		Auxiliary Boiler	Not specified	90	117

Table E-3: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Flares

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	Flare Type	DRE (%)	Flare Gas Recovery
C3P PDH Plant	New Propane Dehydrogenation Plant	2/12/2013		Multi-Stage Ground	98%	
Alpha Olefins Chemical Company, LLC, Freeport, Texas	Alpha Olefins Plant	5/17/2013		Multi-Stage Ground	98%	No
Celanese Clear Lake Plant	Methanol Unit	8/10/2012	PSD-TX-1296-GHG (draft)	Non-assisted	99%	No, not feasible
Chevron Phillips Chemical Co.	Ethylene Unit	12/19/2011	PSD-TX-748-GHG	Low Profile Flare	98%	Not specified
Corpus Christi Liquefaction, LLC	LNG Terminal	9/4/2012		2 Wet Gas Flares/2 Dry Gas Flares	99%	No, not feasible
				Marine Flare	99%	
Delaware Basin JV Gathering, LLC	Gas Processing Facility	1/28/2013		Not specified	98%	No, not feasible
Diamond Shamrock Company, Valero McKee Refinery	Crude Oil Refinery	12/1/2011		Not specified	98%	Yes
DCP Midstream, LP - Hardin County NGL Fractionation Plant	Natural Gas Liquids Fractionation Facility	5/25/2015		Air Assisted	98%	Not specified
DCP Midstream, LP - Jefferson County NGL Fractionation Plant	Natural Gas Liquids Fractionation Facility	7/10/2012		Air Assisted	98%	Not specified
DOW Chemical Company, Light Hydrocarbon 9	Ethylene Production Facility	12/4/2012		Pressure Assisted Flare, Low Pressure Flare	Not specified	Not specified
Enterprise Products Operating, Mont Belvieu Complex Eagleford Fractionation and DIB Units	Natural Gas Liquids Fractionator and Deisobutanizer	5/1/2012	PSD-TX-1286-GHG	Air Assisted	99.5%	Not specified
Enterprise Products, Mont Belvieu Propane Dehydrogenation Plant	Propane Dehydrogenation Plant	12/19/2012		Not specified	Not specified	Not specified
Enterprise Products, Fractionation Units IX and X	Oil and Gas Production	2/14/2013		Not specified	Not specified	Not specified
Energy Transfer Company, Jackson County Plant	Natural Gas Processing Plant	3/15/2012	PSD-TX-1264-GHG	Air Assisted	98%	Not specified
Energy Transfer Partners, LP, Mont Belvieu	Gas Processing Plant	12/7/2011	PSD-TX-93813-GHG	Air Assisted	99%	Not specified

Table E-3: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Flares

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	Flare Type	DRE (%)	Flare Gas Recovery
Equistar Chemical, Olefins Plant Expansion Project - Corpus Christi Project	Olefins and Aromatics Expansion	3/6/2013		Not specified	98%	Not specified
Equistar Chemicals LP, La Porte Complex	Olefins Unit Expansion	9/29/2011	PSD-TX-752-GHG	Steam Assisted	99.5%	No, not feasible
Equistar Chemicals LP, Channelview, Methanol Unit	Restart of Methanol Unit	10/27/2011	PSD-TX-1280-GHG	Steam Assisted	99%	No, not feasible
ExxonMobil Chemical, Baytown Olefins Plant	Olefins Plant	5/22/2012	PSD-TX-102982-GHG (draft)	Staged - steam-assisted elevated flare (for routine continuous emissions) and multi-point ground flare (for routine intermittent emissions)	98% for elevated flare; 99% for ground flare	No, not feasible
ExxonMobil Chemical, Mont Belvieu Plastics Plant	Polyethylene Plant	5/22/2012		Elevated and multi-point ground	99% for VOC with up to 3 carbon atoms, 98% for all other VOCs	Not specified
Formosa Plastics Corporation, Texas, Low Density Polyethylene (LDPE) Plant	LDPE Plant	12/11/2012		Elevated	98%	Not specified
Formosa Plastics, Olefins Expansion	Olefins Expansion and PDH Plant	12/11/2012		Elevated and 2 low pressure ground flares	98% VOCs, 99% methane	Not specified
Freeport LNG Development, Liquefaction Plant	Natural Gas Liquefaction Plant	12/21/2011		Liquefaction Flare: Flare header system and enclosed 11-stage ground flare NGL Flare: flare header and elevated flare	Not specified	Not technically feasible
KM Liquids Terminals	New Condensate Splitter	3/27/2012	PSD-TX-101199-GHG	Air Assisted	98%	Not specified
Lone Star NGL Fractionators LLC, Mont Belvieu Gas Plant	NGL Fractionation Plant	6/7/2013		Air Assisted	98% VOC / 99% methane	No routine vent streams, MSS and emergency only
M&G Resins USA, LLC	Plastic Resin Manufacturing Plant	3/4/2013		Low Pressure	98% VOC / 99% methane	Biogas from WWTP burned in flare during heater maintenance and plant turnaround

Table E-3: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Flares

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	Flare Type	DRE (%)	Flare Gas Recovery
Natgasoline, LLC	Natural Gas to Gasoline Plant	2/19/2013		Not specified	99% for VOC with up to 3 carbon atoms, 98% for all other VOCs	Technically infeasible due to low volume of gas sent to flare on a continuous basis
Occidental Chemical Corporation, Natural Gas Fractionation Facilities, Ingleside Chemical Plant	NG Fractionation Plant	5/21/2012		Enclosed	99% for VOC with up to 3 carbon atoms, 98% for all other VOCs	Not specified
OCI Beaumont LLC	Methanol Unit Primary Reformers	12/21/2012		Methanol Plant - Not specified	98%	Not specified
				Ammonia Plant - Not specified	98%	Not specified
				Reformer MSS - Not specified	98%	Not specified
				Marine Vapor Control System - Not specified	98%	Not specified
ONEOK Hydrocarbon	NGL Fractionation Plant	9/21/2012	PSD-TX-106921-GHG (draft)	Air Assisted	99%	Yes
PL Propylene	Propane Dehydrogenation Plant	2/2012	PSD-TX-18999-GHG	Ground Level Process/Emergency Flare	98%	Pilot gas is the only continuous stream
Targa Gas Processing	Natural Gas Processing Plant	2/23/2012	PSD-TX-106793-GHG	Flare 1 - Air Assisted Flare 2 - Unassisted	98%	Pilot gas is the only continuous stream
Targa Midstream Services	NGL Fractionation Plant	3/26/2012		Not specified	99% for VOC with up to 3 carbon atoms, 98% for all other VOCs	Technically infeasible - CO_2 rich vent stream cannot be used as fuel for the facility

Table E-4: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Equipment Leak Fugitives

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	LDAR Program Selected
C3P PDH Plant	New Propane Dehydrogenation Plant	2/12/2013		28VHP, 28CNTQ
APEX Bethel Energy Center, Anderson County, Texas	Compressed Air Energy Storage Facility	6/22/2012		Monthly inspections using AVO
APEX Matagorda Energy Center, LLC	Compressed Air Energy Storage Facility	11/27/2012		Monthly inspections using AVO
Alpha Olefins Chemical Company, LLC, Freeport, Texas	Alpha Olefins Plant	5/17/2013		28MID (gas and light liquid service components) and AVO (heavy liquid components)
BASF FINA Petrochemicals LP	Ethylene Cracker	5/17/2011	PSD-TX-903-GHG	28LAER
Calhoun Port Authority	Natural Gas-Fired Power Plant	6/20/2012		AVO, 28VHP
Calpine Corporation, Deer Park	Combustion Turbine Generator/HRSG	9/1/2011	PSD-TX-979-GHG	As-observed AVO
Calpine Corporation, Channel Energy Center	Combustion Turbine Generator/HRSG	11/3/2011	PSD-TX-955-GHG	As-observed AVO
Celanese Clear Lake Plant	Methanol Unit	8/10/2012	PSD-TX-1296-GHG (draft)	28LAER and AVO
Chamisa CAES at Tulia, LLC	Compressed Air Energy Storage Facility	11/6/2012		Periodic AVO inspections for natural gas pipeline fugitives
Cheniere Corpus Christi Pipeline, Sinton Compressor Station	Natural Gas Pipeline Compressor Station	8/31/2012		No specified LDAR Program, but annual infrared sensing proposed
Chevron Phillips Chemical Co.	Ethylene Unit	12/19/2011	PSD-TX-748-GHG	28LAER
Copano, Houston Central Gas Plant	Cryogenic Process Unit	6/6/2012	PSD-TX-104949-GHG	28M
Corpus Christi Liquefaction, LLC	LNG Terminal	9/4/2012		28VHP
Delaware Basin JV Gathering, LLC	Gas Processing Facility	1/28/2013		28VHP
Diamond Shamrock Company, Valero McKee Refinery	Crude Oil Refinery	12/1/2011		28VHP

Table E-4: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Equipment Leak Fugitives

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	LDAR Program Selected
DCP Midstream, LP - Hardin County NGL Fractionation Plant	Natural Gas Liquids Fractionation Facility	5/25/2012		28M
DCP Midstream, LP - Jefferson County NGL Fractionation Plant	Natural Gas Liquids Fractionation Facility	7/10/2012		28LAER
DOW Chemical Company, Hydrocarbon 9	Ethylene Production Facility	12/4/2012		28VHP
El Paso Electric Company, Montana Power Station	Electric Generating Station	4/20/2012		AVO
Enterprise Products Operating, Mont Belvieu Complex Eagleford Fractionation and DIB Units	Natural Gas Liquids Fractionator and Deisobutanizer	5/1/2012		28LAER
Enterprise Products, Mont Belvieu Propane Dehydrogenation Plant	Propane Dehydrogenation Plant	12/19/2012		28LAER
Enterprise Products, Fractionation Units IX and X	Oil and Gas Production	2/14/2013		28LAER
Energy Transfer Company, Jackson County Plant	Natural Gas Processing Plant	3/15/2012	PSD-TX-1264-GHG	28LAER
Energy Transfer Partners, LP, Mont Belvieu	Gas Processing Plant	12/7/2011	PSD-TX-93813-GHG	28LAER
Equistar Chemical, Olefins Plant Expansion Project - Corpus Christi Complex	Olefins and Aromatics Expansion	3/6/2013		28VHP
Equistar Chemicals, Channelview, Olefins 1 &2 Expansion - Channelview, TX	Olefins Production	5/15/2012	PSD-TX-1272-GHG (draft)	28LAER
Equistar Chemicals LP, La Porte Complex	Olefins Unit Expansion	9/29/2011	PSD-TX-752-GHG	28LAER
Equistar Chemicals LP, Channelview, Methanol Unit	Restart of Methanol Unit	10/27/2011	PSD-TX-1280-GHG	28LAER

Table E-4: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Equipment Leak Fugitives

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	LDAR Program Selected
Exelon La Porte Mountain Creek Steam Electric Expansion Project	Steam Electric Generation Facility	11/30/2012		AVO
ExxonMobil Chemical, Baytown Olefins Plant	Olefins Plant	5/22/2012	PSD-TX-102982-GHG (draft)	28VHP and weekly AVO
ExxonMobil Chemical, Mont Belvieu Plastics Plant	Polyethylene Plant	5/22/2012		AVO for natural gas components, 28VHP with CNQT for VOCs
FGE Power, LLC	Electric Generating Station	5/6/2013		Daily AVO
Flint Hills Resources Corpus Christi, LLC, West Refinery	Refinery Expansion	12/18/2012		28VHP
Formosa Plastics Corporation, Texas, Low Density Polyethylene (LDPE) Plant	LDPE Plant	12/11/2012		Weekly AVO
Formosa Plastics, Olefins Expansion	Olefins Expansion and PDH Plant	12/11/2012		Weekly AVO
Formosa Plastics Corporation, Texas, Gas Turbines	Gas Turbines	12/11/2012		Weekly AVO
Freeport LNG Development, Liquefaction Plant	Natural Gas Liquefaction Plant	12/21/2011		28MID and AVO
Golden Spread Electric Cooperative, Antelope Station	Gas Turbine Unit	2/1/2013		Periodic AVO
Golden Spread Electric Cooperative, Floydada Station	Gas Turbine Unit	2/1/2013		Periodic AVO
Guadalupe Power Partners LP	Combustion Turbines	11/13/2012		None specified
INEOS Olefins and Polymers, Chocolate Bayou	Olefins Plant Expansion	7/28/2011	PSD-TX-97769-GHG	28VHP
Invenergy Thermal Development LLC	Simple Cycle Power Generation	6/26/2013		Daily AVO
INVISTA, S.a.r.l.	Nylon Intermediates Plant	3/13/2012	PSD-TX-812-GHG	28VHP

Table E-4: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Equipment Leak Fugitives

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	LDAR Program Selected
KM Liquids Terminals	New Condensate Splitter	3/27/2012	PSD-TX-101199-GHG	28LAER
La Paloma Energy Center	Combined Cycle Electric Generating Plant	7/2012	PSD-TX-1288-GHG (draft)	Daily AVO
Las Brisas Energy Center, LLC	Circulating Fluidized Bed Steam Electric Generation Facility	10/28/2011		None specified
Lone Star NGL Fractionators LLC, Mont Belvieu Gas Plant	NGL Fractionation Plant	6/7/2013		28LAER
Lower Colorado River Authority, Ferguson Plant	Combined Cycle Electric Generating Unit	3/15/2011	PSD-TX-1244-GHG	None
M&G Resins USA, LLC	Plastic Resin Manufacturing Plant	3/4/2013		Weekly AVO
Natgasoline, LLC	Natural Gas to Gasoline Plant	2/19/2013		28VHP
NRG Texas Power LLC, SR Bertron	Combined Cycle Electric Generating Unit	11/26/2012		Normal plant maintenance practices
NRG Texas Power LLC, Cedar Bayou Unit 5	Combined Cycle Electric Generating Unit	11/26/2012		Normal plant maintenance practices
NRG Texas Power LLC, P.H. Robinson Electric Generating Station	Add 6 Simple Cycle Electric Generating Unit	3/4/2013		Normal plant maintenance practices
NRG Development Company, Corpus Christi	Combined Heat and Power Plant	3/27/2013		Weekly AVO
Occidental Chemical Corporation, Natural Gas Fractionation Facilities, Ingleside Chemical Plant	NG Fractionation Plant	5/21/2012		28MID with quarterly monitoring of flanges and connectors
ONEOK Hydrocarbon	NGL Fractionation Plant	9/21/2012	PSD-TX-106921-GHG (draft)	28VHP
Pinecrest Energy Center, LLC	Combined Cycle Electric Generating Unit	2/28/2013		Daily AVO

Table E-4: EPA Region 6 Benchmarking for Greenhouse Gas Emissions in Texas from Equipment Leak Fugitives

Permit Applicant	Description of Plant	Date of Permit Submittal	PSD Permit Number	LDAR Program Selected
PL Propylene	Propane Dehydrogenation Plant	2/2012	PSD-TX-18999-GHG	Annual Remote Sensing/Daily AVO
Rohm and Haas Deer Park	Chemical Manufacturing Facility	10/26/2012		As-observed AVO
Targa Gas Processing	Natural Gas Processing Plant	2/23/2012	PSD-TX-106793-GHG	28LAER
Targa Midstream Services	NGL Fractionation Plant	3/26/2012		28LAER
Tenaska Brownsville Partners, LLC	Gas-Fired Turbine and HRSG	2/15/2013		AVO
Victoria WLE LP, Victoria Power Station	Gas-Fired Turbine and HRSG	2/13/2013		None

Appendix F

Proposed Work Practices, Monitoring, Recordkeeping, and Reporting

Table F-1: Work Practices and Monitoring, Recordkeeping, and Reporting for Heaters

Work Practices	Monitoring[1]	Recordkeeping	Reporting
Good Heater Design and Combustion Practices	Continuous monitoring of excess oxygen in flue gas	Daily average excess oxygen in the flue gas	None
	Continuous monitoring of CO in the exhaust	Daily average CO	None
	Continuous monitoring of exhaust temperature	Daily average exhaust temperature	None
	Continuous monitoring of fuel temperature	Daily average fuel temperature	None
Periodic Heater Tune-Ups	Calibrate fuel gas flow meters in accordance with 40 CFR § 98.3.	Records of meter calibration	None
	Quarterly check of the excess oxygen analyzers	Records of quarterly maintenance performed on the excess oxygen analyzers	None
Preventive Maintenance	Check of instrumentation used to control air/fuel ratio during planned turnaround	Records of preventive maintenance performed for air/fuel control system	None
Inspect Flame Pattern	Annual visual inspection of flame pattern and burner adjustments as needed	Records of annual visual inspections and any adjustments to burners	None
Use of Low Carbon Fuels	Use of totalizing fuel flow meter	Daily average quantity of fuels combusted	None

[1] Continuous monitoring shall have the same definitions as in 40 CFR § 63.7525

Table F-2: Work Practices and Monitoring, Recordkeeping, and Reporting for Boilers

Work Practices	Monitoring[1]	Recordkeeping	Reporting
Good Boiler Design and Combustion Practices	Continuous monitoring of excess oxygen in the flue gas	Daily average excess oxygen	None
	Continuous monitoring of CO in the exhaust	Daily average CO	None
	Continuous monitoring of exhaust temperature	Daily average exhaust temperature	None
	Continuous monitoring of fuel temperature	Daily average fuel temperature	None
Periodic Boiler Tune-Ups	Calibrate fuel gas flow meters in accordance with 40 CFR § 98.3.	Records of meter calibration	None
	Quarterly check of the excess oxygen analyzers	Records of quarterly maintenance performed on the excess oxygen analyzers	None
Preventive Maintenance	Check of instrumentation used to control air/fuel ratio during planned turnaround	Records of preventive maintenance performed for air/fuel control system	None
Inspect Flame Pattern	Annual visual inspection of flame pattern and burner adjustments as needed	Records of annual inspections and any adjustments to burners	None
Use of Low Carbon Fuels	Use of totalizing fuel flow meter	Daily average quantity of fuels combusted	None

[1] Continuous monitoring shall have the same definitions as in 40 CFR § 63.7525

Table F-3: Work Practices and Monitoring, Recordkeeping, and Reporting for Flare

Work Practices	Monitoring	Recordkeeping	Reporting
Flare Design and Good Combustion Practices	Continuous monitoring for presence of flare pilot flame	Continuous recording of the flare pilot flame	None
	Continuous monitoring of mass flow rate	Daily average mass flow rate	None
	Continuous monitoring of waste gas composition	Daily average waste gas composition	None
Flare Minimization	Continuous monitoring of mass flow rate	Daily average mass flow rate	None
	Continuous monitoring of waste gas composition	Daily average waste gas composition	None

Table F-4: Work Practices and Monitoring, Recordkeeping, and Reporting for Fugitives

Work Practices	Monitoring	Recordkeeping	Reporting
Leak Detection and Repair, TCEQ 28VHP and TCEQ 28CNTQ	Quarterly monitoring of accessible valves and connectors with gas analyzer	Records of dates, times, and instrument readings for monitoring. Records of date of repair, repair results, justification for delay of repair, and corrective actions taken for all components for repairs. Percentage of leaking connectors as required to justify reduced monitoring frequency.	None
	Annual monitoring with gas analyzer for valves deemed "difficult-to-monitor"	List of "difficult-to-monitor" components. Records of dates, times, test methods, and instrument readings for monitoring. Records of date of repair, repair results, justification for delay of repair, and corrective actions taken for all components for repairs.	None
	Annual monitoring with gas analyzer for valves deemed "unsafe-to-monitor." If not deemed safe within a calendar year, components will be monitored as soon as it is considered safe to do so.	List of "unsafe-to-monitor" components. Records of dates, times, test methods, and instrument readings for monitoring. Records of date of repair, repair results, justification for delay of repair, and corrective actions taken for all components for repairs.	None
	For relief valves equipped with rupture disc and pressure-sensing device, check the reading of the pressure-sensing device weekly	Record in unit log	None
	Weekly audible, visual, olfactory (AVO) inspections of connectors	Record of inspection noted in operator log or equivalent	None
		Calculate cumulative daily emissions from all components on the delay of repair list. When the cumulative daily emissions from all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown, early shutdown may be required.	Notify TCEQ Regional Manager and local programs within 15 days if it is determined that early shutdown is necessary.
Install Leakless Pumps and Compressors	None	None	None